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Background Information for Proposed SO_2 Emission Standards

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The report discusses the legal alternatives to revising the standard of performance for sulfur dioxide emissions from steam/electric generators with heat inputs greater than 250 million BTU/hour. Alternative sulfur dioxide control technologies are discussed. The environmental and economic impact of various alternative sulfur dioxide standards are discussed, also.

The report contains 50 references to detailed technical reports discussing all aspects of flue gas desulfurization at steam/electric generators.

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Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

July 1978

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TABLE OF CONTENTS

Page

LIST OF ILLUSTRATIONS viii
LIST OF TABLES xii

1.0 INTRODUCTION 1-1

1.1 Background 1-2

- 1.1.1 Present Standard 1-3
- 1.1.2 Revisions of the Standard 1-5

1.2 Statutory Authority 1-7

2.0 DESCRIPTION OF AND RATIONALE FOR THE PROPOSED ACTION 2-1

3.0 LEGAL ALTERNATIVES 3-1

3.1 No Action 3-1
3.2 Delayed Action 3-2
3.3 Nature of Standard and Stringency of Controls 3-2
3.4 Control Practices 3-2

4.0 ALTERNATIVE CONTROL TECHNOLOGIES 4-1

4.1 Burning Low-Sulfur Coal 4-1

- 4.1.1 Availability of Acceptable Coal 4-2

4.2 Fuel Treatment Processes 4-7

- 4.2.1 Physical Coal Cleaning 4-8
- 4.2.2 Chemical Coal Cleaning 4-17
- 4.2.3 Solvent Refined Coal Process 4-31
- 4.2.4 Summary and Conclusions 4-40

4.3 Fluidized Bed Combustion 4-42

- 4.3.1 Overview 4-42
- 4.3.2 FBC System 4-47
- 4.3.3 Status of FBC 4-57
- 4.3.4 FBC Vendors 4-58
- 4.3.5 Summary 4-60

TABLE OF CONTENTS
(Continued)

Page

4.4 Flue Gas Desulfurization 4-60

4.4.1 Overview of Flue Gas Desulfurization Processes 4-60
4.4.2 Sulfur Dioxide Removal 4-64
4.4.3 FGD Process 4-76
4.4.4 FGD Wastes 4-134
4.4.5 Status of Flue Gas Desulfurization Technology 4-137
4.4.6 Vendor Capabilities 4-140
4.4.7 Availability 4-148

5.0 DESCRIPTION OF THE EXISTING ENVIRONMENT 5-1

5.1 The Electric Power Industry in the United States 5-1

5.1.1 Generating Capacity 5-2
5.1.2 Production of Electrical Energy 5-3
5.1.3 Supply of Coal 5-4
5.1.4 Origin and Destination of Coal for New Units 5-6
5.1.5 Long-Range Projections 5-13

5.2 Coal Resources of the United States 5-16

5.2.1 Geographical Distribution of Coal Deposits 5-18
5.2.2 Sulfur Content of U.S. Coals 5-21
5.2.3 Coal-Producing Regions 5-23

5.3 Air Quality 5-23

5.3.1 Ambient SO_2 Concentrations 5-23
5.3.2 SO_2 Emissions 5-28
5.3.3 Air Quality Modeling Results 5-30

5.4 Present Water Environment 5-34

5.4.1 Water Quality 5-35
5.4.2 Water Quality 5-48

5.5 Land Use 5-52

5.5.1 Land Used for the Physical Plant 5-53
5.5.2 Land Used for Solid Waste Disposal 5-54
5.5.3 Current Land Requirements 5-55
5.5.4 Projected Land Requirements 5-56

TABLE OF CONTENTS
(Continued)

Page

5.6 Energy Consumption Associated with Control Measures 5-60

- 5.6.1 Flue Gas Desulfurization 5-60
- 5.6.2 Other Control Options 5-64
- 5.6.3 Energy Penalty Projections (1987-1997) 5-67

6.0 ASSESSMENT OF ENVIRONMENTAL IMPACTS 6-1

6.1 Impacts on Coal Resources and Transportation 6-2

6.2 Air Quality 6-4

- 6.2.1 SO_2 Emissions 6-4
- 6.2.2 Ambient SO_2 Concentrations 6-11

6.3 Water 6-13

- 6.3.1 Water Quantity 6-13
- 6.3.2 Water Quality 6-17

6.4 Land Use 6-17

- 6.4.1 Land Use for the Physical Plant 6-17
- 6.4.2 Land Used for Solid Waste Disposal 6-18

6.5 Ecology 6-21

- 6.5.1 Ecology at the Physical Plant 6-21
- 6.5.2 Ecology at the Disposal Site 6-22

6.6 Energy Penalities Associated with Alternate Strategies 6-23

6.7 Noise 6-27

6.8 Secondary Impacts 6-28

7.0 ECONOMIC IMPACT ANALYSIS 7-1

7.1 Industry Profile 7-1

- 7.1.1 General Industry Background 7-1
- 7.1.2 Predominance of Coal in Electric Power Generation 7-6

TABLE OF CONTENTS
(Continued)

Page

7.2 Cost Analysis of Alternative Emission Control Systems 7-10

- 7.2.1 New Facilities 7-10
- 7.2.2 Basis of Cost Analysis 7-10
- 7.2.3 Estimated Control Costs 7-18

7.3 Other Cost Considerations 7-22

- 7.3.1 Additional Capital and Operating Costs 7-22
- 7.3.2 Energy Penalty Costs Associated with SO_2 Control 7-24

7.4 Economic Impact of Alternative Control Systems 7-24

- 7.4.1 Increased Costs to Utility Industry 7-24
- 7.4.2 Financial Impact on Utility Industry 7-36
- 7.4.3 Effects on Price of Electricity to Consumer 7-40
- 7.4.4 Secondary Economic Impacts 7-50

7.5 Cost-Effectiveness of Revised NSPS 7-83

- 7.5.1 Costs of SO_2 Reduction on a Ton-Per-Year Basis 7-83
- 7.5.2 Limitations of Cost-Effectiveness 7-86

APPENDIX A: SO_2 REMOVAL MECHANISMS AND EFFICIENCY A-1

APPENDIX B: ENERGY REQUIREMENTS B-1

APPENDIX C: REHEAT OF SCRUBBED FLUE GASES C-1

APPENDIX D: FGD SYSTEM PERFORMANCE D-1

APPENDIX E: PLANNED AND OPERATING FGD SYSTEMS E-1

APPENDIX F: CONSTRUCTION SCHEDULE F-1

APPENDIX G: ASSUMED PARAMETERS IN FGD COSTS G-1

APPENDIX H: MEASURES TO IMPROVE FLUE GAS DESULFURIZATION AVAILABILITY AND OPERATING PROBLEMS AND SOLUTIONS H-1

TABLE OF CONTENTS
(Continued)

Page

APPENDIX I: EFFECT OF COAL PROPERTIES ON FGD SYSTEMS I-1

APPENDIX J: FORECASTS OF FUTURE ELECTRIC UTILITY INDUSTRY STRUCTURE J-1

REFERENCES K-1

LIST OF ILLUSTRATIONS

Figure Number		Page
4-1	Meyers/TRW Process Flow Diagram	4-19
4-2	Battelle Process Flow Diagram	4-21
4-3	Hazen Process Flow Diagram	4-23
4-4	KVB Process Flow Diagram	4-26
4-5	LOL Process Flow Diagram	4-28
4-6	BOM/ERDA Process Flow Diagram	4-30
4-7	Solvent Refined Coal Process	4-33
4-8	Percent of United States Bituminous Coal Cleanable to a Given Sulfur Content for Various Cleaning Scenarios	4-41
4-9	Control of Atmospheric Pollution by FBC	4-45
4-10	Generic Process Flow Sheet for Category I Atmospheric FBC of Coal	4-48
4-11	Effect of Ca/S Mole Ratio on Sulfur Retention	4-51
4-12	Generic Process Flow Sheet for Category II Pressurized, Combined Cycle FBC of Coal	4-53
4-13	Generic Process Flow Sheet for Category III - Pressurized, Combined Cycle FBC of Coal (Adiabatic Combustor)	4-54
4-14	Comparison of SO_2 Removal Results - Dolomite Sorbent	4-56
4-15	Flue Gas Desulfurization Processes Tested on Coal-Fired Boilers	4-61
4-16	Schematic of Three-Bed TCA	4-69
4-17	Schematic of Venturi Scrubber and Spray Tower	4-72
4-18	Station Electrical Loss As a Function L/G Ratio and Nozzle Pressure	4-74
4-19	Station Electrical Loss As a Function of Draft Requirements	4-75
4-20	Typical Process Flow Diagram for Lime/-Limestone Scrubbing	4-77
4-21	Scrubber System Operability - Green River No. 1, 2 and 3	4-85
4-22	Effect of Circulating Liquor Flow Rate on SO_2 Removal at Constant Gas Flow 212 M^3/S (450,000 SCFM) Mohave Plant	4-89
4-23	La Cygne Availability History	4-94
4-24	Availability History Sherburne No. 1 and No. 2	4-96
4-25	Simplified Process Diagram for Sodium Carbonate Scrubbing System	4-98

LIST OF ILLUSTRATIONS
(Continued)

Figure Number		Page
4-26	Simplified Process Diagram for Double Alkali System	4-103
4-27	Simplified Diagram for Magnesium Oxide Recovery System	4-114
4-28	Simplified Process Diagram for Wellman Lord Recovery System	4-123
4-29	Inlet and Outlet SO_2 Concentrations During Run No. 1	4-127
4-30	Inlet and Outlet SO_2 Concentrations During Run No. 2	4-128
4-31	Inlet and Outlet SO_2 Concentrations During Run No. 3	4-129
4-32	Flow Sheet - Two-Stage Dry Scrubber/SO_2 Absorber	4-131
4-33	Average Availability for Selected FGD Systems	4-150
5-1	Flow of Coal to New Generating Units from the Western Regions of the Northern Great Plains (in 1000 Tons)	5-11
5-2	Flow of Coal to New Generating Units from the Appalachian Region, from U.S. Bureau of Mines District 15, and from the Mountain Region (in 1000 Tons)	5-12
5-3	Air Quality Control Regions: Status of Compliance with Ambient Air Quality Standards for Sulfur Dioxide	5-27
5-4	System #1-Once-Through Water Management	5-36
5-5	System #2-Partial Recirculatory Water Management	5-37
5-6	System #3-Recirculatory Water Management	5-38
5-7	System #4-Zero Discharge Water Management	5-39
6-1	National Power-Plant SO_2 Emissions under Alternative Control Scenarios, High Growth	6-7
6-2	National Power-Plant SO_2 Emissions Under Alternative Control Scenarios, Moderate Growth	6-8
6-3	Primary Ambient Air Quality Standards	6-12

LIST OF ILLUSTRATIONS
(Continued)

Figure Number		Page
7-1	Percentage Growth Rate Over Previous Year Reported by Major U.S. Utility Systems	7-2
7-2	Annual Peak Reserves as a Percentage of Total Availability Capacity	7-3
7-3	Annual Capacity Factor for the Major U.S. Electric Utilities	7-5
7-4	Aggregate Annual Number of Installed Coal-Fired Units Over 25 MWe on a 5-Year Running Average	7-8
7-5	Average Size of Newly Installed Coal-Fired Units on a 5-Year Running Average	7-9
7-6	Actual and Projected Petroleum Demand and Domestic Production (1950-1985)	7-77
A-1	Effect of Ca/S Mole Ratio on Sulfur Retention	A-3
A-2	Comparison of Performance of Greer and Germany Valley Limestones	A-4
A-3	Comparison of SO_2 Removal Results - Limestone Sorbent	A-6
A-4	Sulfur Retention as a Function of Superficial Gas Velocity	A-7
A-5	Effect of Gas Residence Time on Ca/S Ratio Required to Meet Present EPA SO_2 Emission Standard	A-10
A-6	Comparison of Dolomite No. 1337 and Limestone No. 1359 as SO_2 Sorbents on a Mass Feed Rate Basis	A-14
B-1	Energy Requirements for SO_2 Control - 520 ng/J at 500 MW Plant	B-5
B-2	Energy Penalties for SO_2 and Particulate Control - 90% SO_2 Removal Control Level, 500 MW Plant	B-7
B-3	Energy Requirements for SO_2 and Particulate Control - 220 ng/J Control Level, 500 MW Plant	B-8
B-4	Energy Penalties for SO_2 Control - Summary of Effects of SO_2 Control Level	B-10

LIST OF ILLUSTRATIONS
(Concluded)

Figure Number		Page
D-1	Effect of Inlet SO_2 Concentration on SO_2 Removal Efficiency for Fixed Design and Operating Conditions	D-3
D-2	Effect of Liquid-to-Gas Ratio on SO_2 Removal Efficiency with Low Sulfur Coal at the Mohave Power Station	D-5
D-3	Effect of Liquid-to-Gas Ratio on SO_2 Removal Efficiency - TCA with Limestone	D-6
D-4	Effect of Gas Velocity on SO_2 Removal Efficiency - TCA with Limestone	D-7
D-5	Effect of Scrubber Inlet pH on SO_2 Removal Efficiency - TCA with Limestone	D-8
D-6	Effect of Bed Height on SO_2 Removal Efficiency - TCA with Limestone	D-10
D-7	Effect of Liquid-to-Gas Ratio on SO_2 Removal Efficiency - TCA with Limestone and Magnesium	D-12
D-8	Effect of Scrubber Inlet pH on SO_2 Removal Efficiency - TCA with Limestone and Magnesium	D-13
D-9	Effect of Magnesium on SO_2 Removal Efficiency - TCA (No Spheres) with Limestone	D-14
D-10	SO_2 Absorption Efficiency for Two Scrubbers in Series	D-15
F-1	Construction Schedule for a Typical (500 MW) Power Plant	F-2
F-2	Construction Schedule for a Typical Power Plant Equipped with FGD System	F-3
J-1	Projections of Electric Utility Coal Consumption	J-27

LIST OF TABLES

Table Number Page

4-1 Distribution of Coal Samples by Region and State 4-5
4-2 Estimates of Recoverable Reserves of Raw Coal Characterized by Emission Rate of Sulfur Dioxide from Uncontrolled Combustion 4-6
4-3 Physical Coal Cleaning Process Environmental Problems 4-11
4-4 U.S. Recoverable Reserves to Meet the NSPS, Raw and Prepared Coal to Meet the 1985 Annual Demand from New and Existing Electric Utilities (Standard - lb $SO_2/10^6$ Btu) 4-13
4-5 Typical Analyses of Coals Used 4-36
4-6 Typical Operating Conditions and Results 4-37
4-7 Typical Analyses of Solvent Refined Coal 4-38
4-8 Major Coal Cleaning Process Considerations 4-43
4-9 Selected List of Operational Fluidized Bed Combustors 4-59
4-10 Lime/Limestone Process Evaluation 4-80
4-11 Lime Based FGD Systems in the United States 4-81
4-12 Power Plant and FGD System Design Data 4-83
4-13 Green River Power Station Operational Data FGD Unit 4-84
4-14 Power Plant and FGD System Design Data 4-86
4-15 Power Plant and FGD System Design Data 4-88
4-16 Operational Data - Mohave Horizontal FGD Unit 4-90
4-17 Major Domestic FGD Installations - Limestone Slurry 4-92
4-18 Power Plant and FGD System Design/Operating Data, La Cygne No. 1 4-93
4-19 Sherburne County Generating Plant - Unit 1 - Performance Data 4-97
4-20 Sodium Carbonate Scrubbing Evaluation 4-100
4-21 Double Alkali Process Evaluation 4-104
4-22 CEA/ADL Double Alkali Prototype Scrubber Performance History: Operation and Viability Parameters 4-111
4-23 Magnesium Oxide Scrubbing 4-116
4-24 Operability of MgO System at Mystic No. 6 4-118
4-25 SO_x Emissions Test Results for MgO FGD System - Dickerson 4-120
4-26 Operability Data for Dickerson No. 3 4-120
4-27 Sodium Sulfite Scrubbing Evaluation 4-124

LIST OF TABLES
(Continued)

Table Number		Page
4-28	Spray Dryer/Fabric Filter Process Evaluation	4-132
4-29	Volume of Scrubber Wastes Produced by Typical Nonregenerable Systems over a 30-Year Period	4-135
4-30	Breakdown of FGD Units	4-139
4-31	FGD Applications to Coal-Fired Boilers	4-139
4-32	Approximate Process Distribution of Planned FGD Systems on New Coal-Fired Utility Boilers	4-140
4-33	Projected Utilization of Flue Gas Desulfurization on New Coal-Fired Units	4-141
4-34	Comparison of Supply Versus Demand for FGD Systems on New Coal-Fired Utility Boilers under Present NSPS	4-143
4-35	Comparison of Supply Versus Demand for FGD Systems on Coal-Fired Utility Boilers Under More Stringent NSPS	4-143
4-36	Time Required for FGD System Design, Installation, and Startup	4-144
4-37	Lead Time and Delay Frequency of Various Items in the Design and Installation of an FGD System	4-145
4-38	Guarantees Offered by Manufacturers for SO_2 Removal	4-147
4-39	FGD System Performance Data--Average Values	4-151
5-1	Incremental Coal Demand in 1980 and 1985 Attributed to New Units Scheduled for Operation Between 1978 and 1985	5-7
5-2	Projected Movement of Coal for New Units Scheduled to Become Operational Between 1976 and 1985	5-9
5-3	Predicted National Coal Production	5-14
5-4	Regional Coal Production in High Growth Scenario	5-16
5-5	Reserve Base and Recoverable Reserves of Coal in the United States	5-20
5-6	Reserve Base of Coal in the United States, by State and Sulfur Content	5-24
5-7	Coal Producing Regions of the United States	5-25
5-8	Regional SO_2 Emissions	5-29
5-9	Air Quality Impact - $\mu g/m^3$ (% Federal Ambient Air Quality Standard - SO_2)	5-32

LIST OF TABLES
(Continued)

Table Number Page

5-10 Sluice Water Requirement 5-41
5-11 Base Case: Model Power Plant Water Consumption 5-43
5-12 Base Case: FGD System Make-Up Water Requirement 5-44
5-13 Model Plant System Water Requirements 5-46
5-14 Water Consumed by FGD Systems 5-47
5-15 Range of Concentration of Constituents in Scrubber Liquors Studied 5-51
5-16 Projected Land Requirements for Coal-Fired Electric Generating Plants 5-57
5-17 Range of Concentrations of Chemical Constituents in FGD Sludges from Lime, Limestone, and Double-Alkali Systems 5-59
5-18 Energy Penalties for Model SO_2 Control Systems (520 ng SO_2/J) 5-63
5-19 Analysis Assumptions for the Energy Penalty Associated with Coal Cleaning and Western Coal Transportation 5-65
5-20 Energy Associated with 520 ng/J Standard (10^{18} Joules) 5-66

6-1 Impacts on Regional Production of Coal 6-5
6-2 Regional and National Power-Plant SO_2 Emissions Assuming High Growth 6-9
6-3 Regional and National Power-Plant SO_2 Emissions Assuming Moderate Growth 6-10
6-4 Model Plant System Water Requirements 6-14
6-5 Water Consumed by FGD Systems 6-16
6-6 Projected Land Requirements for Coal-Fired 6- Electric Generating Plants - 90 Percent Scrubbing 6-19
6-7 Projected Land Requirements for Coal-Fired Electric Generating Plants - 220 ng/J (0.5 lb $SO_2/10^6$ Btu) 6-20
6-8 Energy Penalties for Model SO_2 Control Systems 6-24
6-9 Energy Consumed by FGD Systems in 1995 (10^9 Megajoules) 6-26
6-10 Energy Consumed in Transporting Coal to Electric Generating Plants (10^9 Megajoules) 6-27

LIST OF TABLES
(Continued)

Table Number Page

7-1 Orders for Coal-Fired Boilers 7-4
7-2 Projected Electric Capacity Mix 7-7
7-3 Costs of SO_2 Control Alternatives for Level of 1.2 lbs/10^6 Btu 7-15
7-4 Costs of SO_2 Control Alternatives for 90% SO_2 Removal 7-16
7-5 Costs of SO_2 Control Alternatives for Level of 220 ng/J (0.5 lb/10^6 Btu) 7-17
7-6 Incremental Costs of Removing 90% SO_2 (Compared to Costs of Meeting 1.2 lb/10^6 Btu) 7-19
7-7 Environmental Capital Costs for Representative New Plant (1975 dollars) 7-22
7-8 Capital Expenditures 1975-1985 by Type of Pollution Control Equipment 7-23
7-9 O&M Expenses for the Industry 7-23
7-10 Energy Penalty in Mills/KWH for Selected Control Processes, Scenarios and Plant Sizes 7-25
7-11 Alternative Teknekron NSPS Scenarios 7-26
7-12 Nationwide Costs of Generating Electricity under Alternative NSPS 1986-1995 - Moderate Rate of Power Growth 7-30
7-13 Nationwide Costs of Generating Electricity under Selected Alternative of NSPS 1986-1995 - High Rate of Power Growth 7-31
7-14 Pollution Control Costs by Region for Alternative NSPS Revisions, 1986-1995 (Moderate Growth of Power) 7-34
7-15 Pollution Control Costs by Region for Alternative NSPS Revisions, 1986-1995 (High Growth of Power) 7-35
7-16 Capital Investment 7-37
7-17 Long-Term External Financing 7-39
7-18 Return on Equity (Return on Common Stock) 7-41
7-19 Interest Coverage 7-42
7-20 Quality of Earnings 7-43
7-21 Regional Price Impacts on the Electric Utility Industry of Alternative NSPS Revisions, 1995 7-44

LIST OF TABLES
(Continued)

Table Number		Page
7-22	Per Capita Cost of Alternative NSPS Revisions for Investor-Owned Utilities	7-46
7-23	Per Capita Cost of Alternative NSPS for Investor-Owned Utilities	7-47
7-24	1990 Coal Production under Alternative New Source Performance Standards (Electricity Growth Rate of 5.8 Percent Per Year Until 1985 and 5.5 Percent Thereafter)	7-51
7-25	1990 Coal Distribution under the Current New Source Performance Standard of 1.2 lbs. of SO_2 (High Electricity Growth Rate)	7-55
7-26	1990 Coal Distribution under an Alternative New Source Performance Standard of 90 Percent Removal of SO_2 (High Electricity Growth Rate)	7-56
7-27	1990 Ton-Miles of Coal Shipments under the Current New Source Performance Standard of 1.2 lbs. of SO_2 (High Electricity Growth Rate)	7-58
7-28	1990 Ton-Miles of Coal Shipments under an Alternative New Source Performance Standard of 90 Percent Removal of SO_2 (High Electricity Growth Rate)	7-58
7-29	Coal Industry Employment (in Thousands of Employees) Electricity Growth Rate of 5.8 Percent Per Year Until 1985 and 5.5 Percent Thereafter	7-60
7-30	Estimated Regional Income Differential in 1990 Resulting from 90 Percent SO_2 Reduction	7-62
7-31	Required Capacity of Electric Power with FGD Systems	7-66
7-32	Additional Income Resulting from Increased Employment in Power Plant Construction with FGD Systems Moderate Growth Rate of Power	7-68
7-33	Additional Income Resulting from Increased Employment in Power Plant Construction with FGD Systems High Growth Rate of Power and 90% SO_2 Reduction	7-69

LIST OF TABLES
(Continued)

Table Number		Page
7-34	Industry Capacity to Meet FGD Requirements	7-70
7-35	Distribution of FGD Industry Employment Per GW Required for Installation of Additional FGD Equipment	7-71
7-36	Utility Oil and Gas Consumption	7-73
7-37	1990 Generation Capacity (GW)	7-75
7-38	The Share of Imports in U.S. Domestic Petroleum Demand	7-76
7-39	Imports-Petroleum Products and Natural Gas	7-80
7-40	Estimated Increased Import Costs	7-81
7-41	U.S. Balance of Foreign Trade (1969-1973)	7-82
7-42	FGD Cost Effectiveness on a Unit Basis Full Scrubbing 500 MW Plant	7-85
A-1	Estimated Ca/S Mole Ratio to Achieve Varying Sulfur Retention Levels	A-2
A-2	Sorbent Requirement for AFBC to Meet EPA SO_2 Emission Standards Based on Pilot Plant Data	A-8
A-3	Results of Runs at Turndown Conditions	A-13
A-4	Sorbent Requirements for PFBC to Meet EPA SO_2 Emission Standards Based on Pilot Plant Data	A-15
B-1	Process Design Bases for FGD Processes	B-2
B-2	Design Assumptions for Physical Coal Cleaning Facility	B-3
B-3	Energy Requirements for the Processing Operations in FGD Systems	B-4
B-4	Total SO_2 and Particulate Energy Penalty Associated with Different Methods of Controlling SO_2 Emissions - 500 MW Plant, 3.5% Sulfur Coal	B-9
D-1	Plants Reporting 90 Percent or Greater SO_2 Removal	D-28

LIST OF TABLES
(Concluded)

Table Number		Page
G-1	Flue Gas Desulfurization Units	G-2
G-2	Analyses of Coals Used as the Cost Estimating Basis	G-4
G-3	Design Parameters for the FGD Systems	G-5
J-1	Key Scenario Elements Held Constant Throughout the Analysis	J-3
J-2	National Electricity Demand Growth Rates	J-4
J-3	Alternative NSPS Scenarios	J-6
J-4	Definition of Geographic Regions	J-9
J-5	Utility Generating Capacity as of December 31, 1975	J-10
J-6	Scaled Energy Demand Growth Rates, by Region	J-11
J-7	Projected Capacity Mix for Selected Scenarios	J-14
J-8	Projected Capacity Mix, by Region, for the Baseline Scenario with Moderate Growth	J-16
J-9	Projected Coal-Fired Capacity by Regulatory Category	J-20
J-10	Projected Coal Capacity Using Flue Gas Desulfurization	J-21
J-11	Regional Breakdown of Installed FGD Capacity in 1995, Scenario H1.2(90)0.03	J-24

1.0 INTRODUCTION

The present New Source Performance Standard (NSPS) limiting the emissions of sulfur dioxide (SO_2) from coal-fired electric utility steam generators has been in effect since December 1971. Under this standard, SO_2 may not exceed 520 nanograms per Joule (ng/J) heat input (1.2 lb/million Btu).

The U.S. Environmental Protection Agency (EPA) proposes to revise the existing standard in view of technological advances in controlling SO_2 emissions from coal-fired steam generators and the requirements contained in the Clean Air Act Amendments of August 7, 1977. The revised standard is described in the preamble to the regulation published in the Federal Register.

Environmental impacts associated with the proposed standard for SO_2 emissions from coal-fired electric utility steam generators are described in this document. Revisions to the new source performance standards for the emission of particulate matter and oxides of nitrogen (NO_x) from coal-fired electric utility steam generators are also being proposed. These actions and their impacts are the subjects of 3 separate volumes and their supplements.

Several alternatives, ranging from the retention of the present standard to proposing a very stringent standard, have been considered by the EPA. The analysis includes several levels of fractional reduction of SO_2. In addition, a control level of 220 ng/J (0.5 lb $SO_2/10^6$ Btu) has been considered. Discussion of these alternatives and their attendant impacts serves to put into perspective the beneficial and adverse effects expected to result from the promulgation of the revised standard. Information to support the Agency's analysis is derived from in-depth studies sponsored by the Agency to examine the implications associated with each alternative standard, including the proposed standard. This document summarizes the results of those studies up to 15 February 1978 and subsequent minor corrections. These studies are referenced throughout this document. Developments which occurred between 15 February 1978 and the date of proposal are discussed in the supplement.

1.1 Background

In accordance with the provisions of the Clean Air Act,* the Administrator of the U.S. Environmental Protection Agency (referred to as the Administrator in this document) is authorized to promulgate standards of performance for new stationary sources of air pollutants. Under provisions of the Clean Air Act Amendments of 1970 the Administrator was to establish standards of performance that reflect "the degree of emission limitation achievable through the application of the best system of emissions reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated (42 U.S.C. 1857C-6)."

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*The Clean Air Act (42 U.S.C. 1857 et seq.) includes the Clean Air Act of 1963 (P.L. 88-206) and amendments made by the Motor Vehicle Air Pollution Control Act--P.L. 89-272 (20 October 1965), the Clean Air Act Amendments of 1966--P.L. 89-675 (15 October 1966), the Air Quality Act of 1967--P.L. 90-148 (21 November 1967), the Clean Air Amendments of 1971--P.L. 92-157 (18 November 1971) the Energy Supply and Environmental Coordination Act of 1974--P.L. 93-319 (24 June 1974, and the Clean Air Act Amendments of 1977--P.L. 95-95 (7 August 1977).

Under the Clean Air Amendments of 1977, the definition has expanded the scope of a standard of performance and, with respect to any air pollutant emitted from a category of fossil fueled stationary sources to which the standard applies, and stipulate that the standard "reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated (Section III(a)(1)(C))." In establishing a regulatory fractional reduction in emissions resulting from the combustion of fuels, the Administrator may credit "any cleaning of the fuel or reduction in the pollution characteristics of the fuel after extraction and prior to combustion."

1.1.1 Present Standard

On August 17, 1971 (36 FR 15704), the Administrator proposed regulations establishing standards of performance for airborne emissions from new stationary sources in several source categories. Among these were standards for emissions of particulate matter, sulfur dioxide (SO_2), and nitrogen oxides (NO_x) from fossil fuel-fired steam generators. Interested parties were afforded an opportunity to participate in the rule-making by submitting comments and private sectors. Following a review of the proposed regulations and consideration of the comments, the regulations were revised and promulgated on December 23, 1971 (36 FR 24876, 40 CFR 60).

The standards of performance established by the regulations were based on field testing conducted by the Agency and its contractors and on data derived from various other sources, including the available technical literature. In comments to the proposed regulations, many questions were raised as to costs and demonstrated capability of control systems to meet the standards. These comments were given due consideration, and the Administrator judged that the standards corresponded to levels of performance that could be met with demonstrated control systems at reasonable costs.

The regulation pertaining to the emission of SO_2 required that emissions not exceed 520 ng/J heat input (1.2 lb/ million Btu) derived from solid fossil fuel (40 CFR 60.43(a)(2)).* In accordance with definitions contained in the Act or established by regulation, the standard applied to steam generating units of capacity greater than 73 MW heat input (250 million Btu/hour), the construction or modification of which commenced after August 17, 1971.

The SO_2 standard required the application of control systems on plants burning high sulfur coal; and allowed the use of coal of sufficiently low sulfur content and high calorific value whose emissions of sulfur dioxide remained below the regulatory standard.

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*Periods of excess emissions are defined as any two consecutive hourly periods during which average emissions of sulfur dioxide exceed 1.2 pounds per million Btu of heat input (40 CFR 60.45(g)(2)).

1.1.2 Revisions of the Standard

Provisions of the Clean Air Act in effect before enactment of the amendments of August 7, 1977 require the Administrator to review and if necessary revise established standards of performance for new sources as new knowledge and technology became available. On August 6, 1976, the Agency was petitioned by the Oljato and Red Mesa Chapters of the Navajo Tribe and the Sierra Club to revise the standard of performance for the emission of SO_2 from power plants and to require a reduction in emissions of 90 percent from uncontrolled levels. The petition included detailed information to support the claim that a revision of the standard was necessary in view of recent advances in control technology. The Agency agreed to investigate the matter thoroughly and gave notice of its intent to review the new source performance standard for SO_2 (42 FR 5121; Appendix B*). Interested persons were invited to participate in the Agency's efforts by submitting written data, opinions or arguments.

On January 27, 1977, the Agency gave notice of a public hearing to be held on May 25 and 26 (42 FR 18884; Appendix B). The public hearing was held at the General Services Administration Auditorium, in Washington, D.C. A panel was formed consisting of representatives of the Oljato and Red Mesa Chapters of the Navajo Tribe, Sierra Club, the Illinois Pollution Control Board, the Utilities Air Regulatory Group, and of the U.S. Environmental Protection Agency. The panel discussion was made part of the public hearing. Oral presentations were made at the meeting by representatives of Federal, state, and local governmental agencies, industry and commerce, citizens and industrial groups, and individuals in the private sector. The record includes written statements submitted prior to June 6, 1977, by all interested parties.

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*Appendix A is reserved for public comments on this environmental statement.

Pursuant to the amendments of August 7, 1977 to the Clean Air Act, the Administrator is now required to review and, if appropriate revise established new source performance standards at least every 4 years (Section III(b)(1)(B)). Revised standards reflecting a fractional reduction in emissions resulting from the combustion of fuels are to be promulgated within 1 year of the enactment of the amendments (i.e. by August 7, 1978).

Proposed revisions to the present standard for SO_2 emissions from electric utility steam generators have been discussed at two meetings of the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) held in Alexandria, Virginia, on September 28 and on December 14 and 15, 1977. Public comments in both oral and written form are included in the records of these meetings.

1.2 Statutory Authority

Authority to promulgate and revise standards of performance for new sources is derived from Section III of the Clean Air Act. The Administrator is directed to establish standards relating to the emission of air pollutants from new stationary sources and is accorded discretionary power to:

1. Identify categories of stationary sources that cause or contribute significantly to air pollution, where it may reasonably be anticipated that public health or welfare would be endangered.

2. Distinguish among classes, types and sizes within categories of new sources for the purpose of establishing standards.

3. With respect to any air pollutant emitted from a category of fossil fuel fired stationary sources to which the standard applies, to establish a standard of performance that reflects the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

The term "stationary source" encompasses all buildings, structures, facilities or sources that emit or may emit any air pollutant. A source is considered new if its construction or modification commences after the publication of proposed regulations. Modifications subjecting an existing source (any stationary source other than a new source) to regulatory standards are considered to be physical changes in the stationary source or changes in the method of operation, provided that such changes lead to an increase in the amount of any air pollutant not previously emitted.

2.0 DESCRIPTION OF AND RATIONALE FOR THE PROPOSED ACTION

The material intended to be presented in this section, appears in the preamble to the regulation published in the Federal Register.

3.0 LEGAL ALTERNATIVES

Under the present provisions of the Clean Air Act incorporating the amendments of August 7, 1977, the Administrator is directed to review and, if appropriate, revise established standards governing the release of airborne pollutants from new stationary sources (PL 95-95, Section III(b)(1)(B)). With respect to fossil fuel-fired stationary sources to which a revised standard may apply, the standard must:

1. Reflect a fractional reduction of emissions relative to the corresponding emissions from the combustion of untreated fuel (PL 95-95, Section III(a)(1)(A)(ii))
2. Reflect the application of the best technological system of emission reduction (PL 95-95, Section III(a)(1)(C))
3. Take effect 1 year after the enactment of the amendments of August 7, 1977 (PL 95-95, Section III(b)(1)(B)(6))

3.1 No Action

Under the Clean Air Act Amendments of 1977, no action is required by the Agency in revising the new source performance standard for the emission of sulfur dioxide from coal-fired electric utility steam generators if the existing standard reflects the application of the best technological system of emission reduction.

On the basis of the information and the analysis set forth in this statement, the Administrator has determined that demonstrated technology is available to limit the emissions of sulfur dioxide from coal-fired electric utility steam generators to levels lower than might be allowable under the present standard. Accordingly, the

Administrator has the responsibility for revising the existing standard and establishing one that reflects the application of the best technological system of emission control.

3.2 Delayed Action

The Administrator has no discretionary power to delay the establishment of a revised standard.

3.3 Nature of Standard and Stringency of Controls

The Administrator has no discretionary power to establish a revised standard other than one expressed in terms of a fractional reduction in emission levels. A proposed fractional reduction of 85 percent, with added provisions for maximum allowed emissions and maximum required levels of control, has been selected based on: the availability of demonstrated technology to achieve this reduction, the properties of U.S. coal reserves, and the environmental considerations documented in this report.

3.4 Control Practices

The proposed fractional reduction in SO_2 emissions can be achieved by treatment of the flue gases from the combustion of coal or by a combination of flue gas treatment and coal treatment to reduce sulfur content prior to combustion. Technologies under development, are the conversion of coal to clean fuels and the combustion of coal in a fluidized bed containing sorbent material. The proposed standard allows credit to be taken for any and all techniques applied to reduce the emission of sulfur dioxide and, therefore, conforms with the provision of the Clean Air Act stipulating that such credit be given (PL 95-95, Section III(a)(1)(C)). No alternative form of standard would comply simultaneously with this and the other stipulations of the Act discussed above.

4.0 ALTERNATIVE CONTROL TECHNOLOGIES

Sulfur is a natural constituent of practically all coal. During coal combustion, most of its sulfur content is converted to gaseous sulfur compounds. In the absence of emission control devices, these compounds* and other products of combustion are released. Methods of limiting the emission of sulfur compounds fall into four broad categories:

- Burning low-sulfur coal.
- Cleaning coal before combustion to remove part of its sulfur content.
- Retaining sulfur during or immediately following combustion in sorbent material mixed with the fuel coal.
- Processing of flue gases (flue gas desulfurization). In principle, combinations of two or more of these techniques could be applied to achieve a given degree of sulfur retention.

4.1 Burning Low-Sulfur Coal

Burning of coal leads to the volatilization of its sulfur content and, in the absence of control equipment, the release of practically all of the sulfur from the combustion system. A small fraction of the sulfur liberated from the coal, generally 5 percent of the amount present, is retained within the ash or other deposits in the system. The remainder is released predominantly as sulfur dioxide, with a small amount of sulfur trioxide.

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*As a general rule, 95 percent by weight of the sulfur present in bituminous and subbituminous coal is released as gaseous sulfur compounds from a utility boiler without sulfur control devices (U.S. Environmental Protection Agency, 1974). Sulfur is released predominantly as sulfur dioxide. A very small portion of the emissions may consist of sulfur trioxide.

Clearly, the quantity of sulfur dioxide released from a steam generator burning coal varies with the sulfur content. The feed rate of coal in a given system is governed by the capacity of the system, its thermal efficiency, and the heat content or calorific value of the coal. These parameters effectively determine the rate at which sulfur dioxide is emitted from a given generator. More specifically, the emission rate of sulfur dioxide can be expressed in terms of the mass of sulfur dioxide released per unit of heat input to the system or as the number of pounds of sulfur dioxide released per million Btu of heat input. Both the sulfur content and the heating value of the fuel, therefore, influence the normal release rate of sulfur dioxide. These two properties determine whether the burning of a particular coal meets regulatory limitations.

4.1.1 Availability of Acceptable Coals

Surveys of the U.S. coal reserve base show low sulfur coal is present predominantly in the western states. However, most western coals are of a lower rank than eastern coals and, when allowance is made for differences in heating value, the estimated low sulfur fraction of the reserve base in the west drops from 84 percent to a maximum of 80 percent (U.S. Department of the Interior, Bureau of Mines, 1976). With respect to rank, 22 percent of the coal with a sulfur content lower than 1 percent is of high rank (anthracite and bituminous) and 78 percent is of low rank (subbituminous and lignite).

States with the largest quantities of low sulfur coal are Alaska, Montana, and West Virginia. Montana has an estimated reserve base of 102 billion tons, or 51 percent of the total reserves; West Virginia has 7 percent; and Alaska has 6 percent. Virtually all of the Montana and Alaskan coals are of low rank; whereas all of the West Virginia coals are high rank bituminous coals. Of the high rank low sulfur coals 82 percent of the reserve base is amenable to underground mining, while only 58 percent of the reserves of low rank low sulfur coals could be recovered.

Certain low sulfur coals with low contents of mineral matter (generally no greater than 8 percent) are suitable for coking and subsequent use in metallurgical production and other industrial processes (U.S. Department of the Interior, Bureau of Mines, 1976). It is estimated that 90 percent of all coking coals are in the Appalachian coal region. West Virginia has the largest quantities of premium quality coking coal. Of the 14.1 billion ton reserve base of low sulfur bituminous coal in West Virginia, 10.5 billion tons are considered to be of premium grade suitable for use in coke production (U.S. Department of the Interior, Bureau of Mines, 1975, 1976). Other states with substantial deposits of coking coal are eastern Kentucky and Pennsylvania.

Little information is available on the sulfur content and heating value of coals distributed throughout the U.S. reserve base. A sampling program to estimate the potential reduction in sulfur dioxide emissions that could be realized by washing U.S. coals yielded data characterizing coals on the basis of emission rates of sulfur dioxide per unit of heat input (U.S. Environmental Protection Agency, 1976). The program analyzed 455 coal samples collected from surface and deep mines currently producing coal primarily for use by electric utilities. Samples included in the survey are drawn from mines producing in aggregate more than 70 percent of the current total annual consumption of the utility industry. The distribution of samples by region and state is shown in Table 4-1. The number of samples varies greatly among regions and states. Since the intent was to characterize steam coal currently being produced, information for the eastern regions is more precise than that for reserves in the western midwest and western regions.

The results of the survey are combined with data on the recoverable reserves of coal in the United States to yield the estimates shown in Table 4-2. As indicated in the table, approximately 110 billion tons of coal or 42 percent of all recoverable reserves could be burned without pretreatment or controls and without exceeding the present regulatory standard of performance of 1.2 pounds of sulfur dioxide per million Btu of heat input. Approximately 70 percent of the recoverable reserves in the western region meet this criterion, 12 percent in the eastern region and 5 percent or less in the eastern and western midwest regions. Reducing the standard to

TABLE 4-1

DISTRIBUTION OF COAL SAMPLES BY REGION AND STATE

REGION	STATE	NUMBER OF SAMPLES
Eastern	Alabama	10
	Eastern Kentucky	7
	Maryland	34
	Ohio	58
	Pennsylvania	103
	Tennessee	8
	West Virginia	44
	Total	272
Eastern Midwest	Illinois	40
	Indiana	20
	Western Kentucky	35
	Total	95
Western Midwest	Arkansas	3
	Iowa	17
	Kansas	8
	Missouri	9
	Oklahoma	77
	Texas	0
	Total	44
Western	Alaska	0
	Arizona	6
	Colorado	11
	Montana	5
	New Mexico	9
	North Dakota	1
	South Dakota	0
	Utah	8
	Washington	0
	Wyoming	4
	Total	44
	Total, All Regions	455

TABLE 4-2

ESTIMATES OF RECOVERABLE RESERVES OF RAW COAL CHARACTERIZED BY EMISSION RATE OF SULFUR DIOXIDE FROM UNCONTROLLED COMBUSTION

REGION	RECOVERABLE RESERVE* (MILLIONS OF TONS)	EMISSION RATE OF SULFUR DIOXIDE							
		1.2LB $SO_2/10^6$BTU		0.8LB $SO_2/10^6$BTU		0.6LB $SO_2/10^6$BTU		0.4LB $SO_2/10^6$BTU	
		% OF RESERVE	MILLIONS OF TONS	% OF RESERVE	MILLIONS OF TONS	% OF RESERVE	MILLIONS OF TONS	% OF RESERVE	MILLIONS OF TONS
Eastern	58,000	12	7,000	2	1,200	<1	0	0	0
Eastern Midwest	51,000	1	510	0	0	0	0	0	0
Western Midwest	13,000	5	650	2	260	0	0	0	0
Western	140,000	70	98,000	41	57,000	16	22,000	2	2,800
TOTAL U.S.	262,000	42	110,000	22	58,000	8.4	22,000	1.1	2,800

*See Table 4-1.

Source: Adapted from Battelle Memorial Institute, 1977.

0.8 pounds would reduce the fraction of recoverable reserves that could meet regulatory requirements to 2 percent or less in the eastern, eastern midwest, and western midwest regions and 41 percent in the western region. Nationwide, 58 billion tons or 22 percent of recoverable reserves of coal would have the requisite properties with respect to sulfur content and heating value. Further reductions of the standard would eliminate practically all coals except those of western origin. At a standard of 0.6 pounds, 16 percent of coals in the western region, or 22 billion tons of reserves, would be acceptable. At 0.4 pounds, 2 percent of western reserves, or 2.8 billion tons, could meet regulatory requirements.

4.2 Fuel Treatment Processes

The effectiveness of fuel treatment processes as a sulfur dioxide emission control technology depends on the cleanability of the coal (the amount of sulfur that can be removed). Sulfur is present in the coal as either inorganic sulfur, such as pyrite, or organic sulfur. The principal categories of fuel treatment are physical and chemical coal cleaning and the application of the solvent refined coal (SRC) process.

The physical coal cleaning methods are the conventional technologies that are commonly applied; however, sulfur removal is limited. These technologies are typically employed to remove carbonaceous shale, gypsum, Kaolin, calcite, and pyrite to produce better quality fuel rather than strictly for sulfur removal.

The chemical coal cleaning processes being developed remove more of the pyritic sulfur and, in many cases, some of the organic sulfur. The chemical methods or processes that are not limited in terms of sulfur removal are currently in the developmental stages and have produced little or no operating data.

The SRC process under development involves dissolving pulverized raw coal in a coal-derived solvent. In the process, mineral matter (ash) and pyrite and organic sulfur are removed, producing a liquid which when cooled to ambient temperature becomes a solid material that can be burned in modified pulverized-coal boiler.

Extensive studies show that fuel treatment processes result in reduced sulfur content for many medium to high sulfur coals. The reduction and total amount of coal that can be cleaned depends on many variables which are discussed in the following sections.

4.2.1 Physical Coal Cleaning

Physical cleaning can be defined generally as the separation of waste or unwanted "refuse" material from coal by techniques based on the differences in the physical properties of coal and refuse. The most common physical property used in coal cleaning is density. Specific gravity ranges are generally:

Coal (1.2 to 1.8)
Carbonaceous shale (4)
Pyrite (5)
Gypsum, kaolin, calcite (2.3 to 2.9)

Density separation is done using hydraulic jigs, laundering tables, cyclones, dense medium vessels, or air classifiers. In such equipment, ground coal is suspended in a fluid, the refuse material falls to the bottom of the separating unit, and the cleaned coal floats or moves to the top of the unit for removal. Froth flotation, a related technique, also uses the surface properties of coal particles to enhance separation. Physical cleaning removes mineral sulfur such as pyrite, which has a high density, but not organic sulfur, which is an integral part of the coal. The amount of mineral sulfur removed depends on the crystal size; the smaller the crystals, the smaller run of the mine (ROM) coal must be crushed to achieve effective separation. Large amounts of coal will be lost with the refuse if the particle sizes of the mineral sulfur and pulverized coal are not matched well and if a large fraction of the mineral sulfur is to be removed. As the coal is pulverized to smaller and smaller particles, costs of pulverization rise quickly. These costs vary widely depending on the type of coal.

The Btu recovery rate of the cleaning process is usually based on the input heating value. The heating value of the coal lost in the refuse is counted as an energy loss. Physical cleaning generally has a Btu recovery of 80 to 95 percent of the ROM coal, with the largest losses associated with coal lost with the refuse and with the coal required to operate the thermal drier. One can expect physical cleaning to remove 35 to 70 percent of the mineral sulfur (inorganic) in ROM coals, depending on the amount of size reduction and the other physical characteristics of the coal. However, while

while physical coal cleaning removes much of the mineral sulfur, the organic sulfur (not removed by physical cleaning) can make up 30 to 70 percent of the sulfur in a particular coal.

Several other techniques can be used in physical cleaning, such as magnetic separation of iron pyrite (FeS_2), oil agglomeration, and electrophoretic and electrostatic separation. Either for economic or processing reasons, they have not been developed sufficiently to warrant a detailed discussion.

Physical coal cleaning reduces sulfur and ash content. While this is done primarily to improve fuel quality and consistency the result enhances the environmental acceptablity of burning the cleaned coal. However, physical cleaning has its own set of environmental problems. The refuse is usually gob piled. These piles can be a source of pollution similar to acid mine drainage and may require a collection and lime treatment system for the drainage. Gob piles can also be sources of fugitive dust. Table 4-3 gives generalized potential environmental problems associated with the various process technologies.

Physical coal cleaning reduces the sulfur and ash contents and, hence, reduces costs of transportation and particulate removal and ash handling at the power plant. In addition, SO_x and particulate emissions are reduced. Process reliability is a minor problem, since most of the systems have been used in the mining industry for years. However, for certain coals, the reduction of sulfur content is limited

TABLE 4-3

PHYSICAL COAL CLEANING PROCESS ENVIRONMENTAL PROBLEMS

TECHNOLOGY	PROBLEM	CONTROL METHOD
Jig, laundry, cyclone, table	Contaminated process water	Closed water cycle
Dense medium vessel and cyclone	Contaminated process water dense media loss	Closed water cycle
Air classifier	Fugitive coal dust	Cyclone collector, bag house electrostatic precipitator (ESP)
Froth flotation	Contaminated process water, flotation reagents loss	Closed water cycle
Electrostatic	Fugitive coal dust	Cyclone collector, bag house ESP
Electrophoretic	Contaminated process water	Closed water circuit
Magnetic	Contaminated process water	Closed water circuit
Oil agglomeration	Contaminated process water, fuel oils, tar oil in contact with water	Closed water and oil circuit

because the organic sulfur cannot be removed. As a result, not all coals can be cleaned to meet the new source performance standard (NSPS), and as it is lowered, the applicability of physical coal cleaning diminishes. Table 4-4 shows the effect of changes in the standard on the cleanable coal reserve. These figures are also optimistic, since it is assumed that the utilities have access to 100 percent of the coal (typically a portion of the more desirable coals, i.e., metallurgical coals, goes to industry at premium prices) and that production can be shifted to produce this coal. However, physical coal cleaning might be used with another control option such as flue gas desulfurization (FGD). If physical coal cleaning, a relatively low-cost process, is used to reduce the sulfur content to near the NSPS compliance level, then FGD, a relatively high-cost process, can be used to treat a portion of the flue gas stream to achieve NSPS compliance. The size of the FGD unit and, hence, its cost would be reduced. A further benefit would accrue from using FGD on only a portion of the flue gas if the recombined treated and untreated flue gas streams retain sufficient buoyancy so that reheating is not required to achieve plume rise.

The economics of combined Physical Coal Cleaning (PCC) and FGD have been analyzed by Hoffman-Munter Corporation in a study for the Bureau of Mines, and by PEDCo Environmental Incorporated in a study for the U.S. Environmental Protection Agency. These studies show that a lower cost can be expected by using the combined technologies if the

TABLE 4-4

U.S. RECOVERABLE RESERVES TO MEET THE NSPS,
RAW AND PREPARED COAL TO MEET THE
1985 ANNUAL DEMAND FROM NEW AND EXISTING ELECTRIC UTILITIES
(STANDARD - LB $SO_2/10^6$ BTU)

	RECOVERABLE RESERVES							
	2.0		1.2		0.8		0.4	
LEVEL OF COAL PREPARATION	%	10^6 TONS	%	10^6 TONS	%	10^6 TONS	%	10^6 TONS
RAW COAL	23	59,754	14	36,372	2	5,196	0	0
1.5",>90% Btu	36	93,527	24	62,352	4	10,392	0	0
14 Mesh,>50% Btu	48	124,703	32	83,135	7	18,186	0	0
1985 DEMAND FROM ALL UNITS (EXISTING AND NEW) 788.3 x 10^6 Tons Annually								
YEARS OF AVAILABLE SUPPLY FROM RECOVERABLE RESERVES*								
RAW COAL		76		46		7		0
1.5",>90% Btu		119		79		13		0
14 Mesh,>50% Btu		158		105		23		0

*Based on 1985 demand level.
Source: Battelle Memorial Institute, 1977.

sulfur content of the cleaned coal is near compliance levels. As the difference between sulfur content and compliance level increases, FGD must be used on a greater percentage of the flue gas. At some point, a crossover occurs where it is no longer economical to use PCC in conjunction with FGD. This is because scrubbers have a size/cost exponential relationship of 0.8. As the scrubber size becomes larger, economics of scale make it more attractive to totally utilize scrubbers as the cleaning system and dispense with the coal cleaning. In addition, as more of the flue gas is scrubbed, reheating becomes necessary and the benefit of the combined technologies also diminishes. It is difficult to generalize, because the necessary analysis of costs and effectiveness must be performed specifically for each power plant, but if more than 50 percent of the flue gas must be scrubbed to achieve compliance, it is likely that combined PCC and FGD will not be the lowest cost option. In conclusion, the more stringent the NSPS, the less useful physical coal cleaning becomes as an alternative control option.

Battelle Memorial Institute (1977) has studied the costs of physically cleaning easily cleaned northern Appalachian coals, presenting cost data for coals cleaned at a top size of 0.95 cm (3/8 inch), and high yield factors (a range of 85 to 95 percent of input product yield, weight basis). Other Appalachian coals generally have a 60 to 70 percent weight yield (Battelle Memorial Institute, 1977), and the associated costs would be higher on a cleaned-coal basis. Capital investment for a physical cleaning plant larger than 454 kkg (500 tons) per hour capacity at the mine mouth (a lower practical economic limit) can cost between $9,920 and $49,600 per kkg ($9,000 and $45,000 per short ton) per hour capacity (Battelle Memorial Institute, 1977). The higher value, $49,600, includes rail spurs, and coal handling equipment normally associated with mine facilities costs. The mean cost range is $16,500 to $19,800 per kkg ($15,000 to $18,000 per short ton) per hour capacity. These mean costs are incremental to mine facility costs, e.g., rail spurs, conveyors.

Assuming the following:

(1) 15-year capital write-off

(2) 13 productive hours per day, 260 days per year operation

(3) interest rate of 10 percent

(4) 90 percent product yield

(5) $19,800 per ton per hour of capacity capital cost

one can expect a capital charge of $.845 per kkg ($.767 per ton) of ROM coal processed for a 454 kkg (500 short tons) per hour plant, and an operating and maintenance cost of $.76 to $.94 per kkg ($.65 to $.80 per short ton) of ROM coal processed, depending on the site and coal specifics of the cleaning plant. The operating and maintenance cost includes an allowance for disposal costs of the refuse. Because of the loss of rejects material in cleaning, and because the heating value is an important factor in selling the cleaned coal, costs are usually reported in dollars per million Btu. If the coal is assumed to go from a ROM heating value of 25.58 MJ per kg (11,000 Btu per pound) to a product heating value of 27.91 MJ per kg (12,000 Btu per pound), with a ROM coal price of \$19.80 per kkg (\$18 per ton), and a 90 percent weight yield, the cost of cleaning would be calculated as follows:

$$\text{Raw Coal Cost} = \frac{\$19.80 \text{ per kkg}}{(25.58 \text{ MJ/kg})\ (1000 \text{ kg/kkg})} = \$.774/\text{GJ}$$

$$\text{Cleaned Coal Cost} = \begin{array}{rl} \$19.80 & \text{ROM coal cost} \\ .84 & \text{capital charge} \\ \underline{.94} & \text{O\&M cost} \\ \$21.58 & \text{per kkg ROM coal} \end{array}$$

$$\frac{\$21.58}{.9 \text{ yield}} = \$23.98/\text{kkg cleaned coal}$$

$$\frac{\$23.98/\text{kkg}}{(27.91 \text{ MJ/kg})\ (1000 \text{ kg/kkg})} = \$.859/\text{GJ}$$

$$\text{Cleaning cost} = \$.859 - \$.774 = \$.085/\text{GJ or } \$.09/10^{6}\text{Btu}$$

$$\frac{\$19.57}{.9 \text{ yield}} = \$21.74/\text{ton cleaned coal}$$

$$\frac{\$21.74/\text{ton }(10^{6})}{(12{,}000 \text{ Btu/lb})\ (1000 \text{ lb/ton})} = \$.906/10^{6} \text{ Btu cleaned coal}$$

$$\text{Cleaning cost} = \$.906 - \$.818 = \$.087/10^{6} \text{ Btu}$$

This cost is for a plant using hydraulic jigs, washing tables, cyclones, froth flotation units, filters, screens, and mechanical and thermal driers. Using the cleaned coal as a basis, the cleaning cost is then $2.37 per kkg (2.09 per ton). If the cleaning yield is assumed to be a more typical 60 weight percent, the ROM heating value of the coal is 18.61 MJ per kg (8,000 Btu per pound), and a ROM coal price of $11 per kkg ($10 per ton) is used, the capital charges and operating and maintenance costs used above then give a cleaned coal processing cost of $4.80 per product kkg ($4.27 per product short ton), and $.172 per GJ ($0.178 per million Btu's). These figures do not include any profit for the operation.

4.2.2 Chemical Coal Cleaning

Chemical coal cleaning has an advantage over physical methods in that it has the potential for removal of nearly all of the inorganic sulfur, and some of the organic sulfur as well. However, most of the systems are in the development or pilot stages and have not yet been totally demonstrated. As a result, no acceptable reliability data are available. Further, some of the processes have environmental problems which are difficult to resolve.

There are currently about 25 chemical cleaning processes under active development and many more in conceptual stages. There is economic information available for eight of these processes.

4.2.2.1 Meyers/TRW Process. The Meyers process is the most highly developed of the chemical cleaning processes. This process leaches - 149 μm (-100 mesh) coal containing iron pyrite (FeS_2) with ferric sulfate $Fe_2(SO_4)_3$, converting the pyrite to sulfuric acid, ferrous sulfate, and elemental sulfur. The process operates at moderate temperatures and pressure, 70°C to 120°C and 100 Kn/m^2 to 550 Kn/m^2 (15 to 80 psia). Leaching times are 5 to 10 hours. The process has no proven organic sulfur removal. Elemental sulfur produced is solvent extracted or vaporized and recovered by condensation. Figure 4-1 indicates the layout involved in the Meyers/TRW process.

Dow Chemical has performed an extensive design and economics study of this process for a 420 kkg (380 short tons) per hour plant. Their total capital cost for this design was $145 million (mid-1975 dollars) plus or minus about 20 percent. This includes limited physical cleaning facilities for removal of rock aggregate and shale. Dow feels that based on this design and 95 percent removal of pyritic sulfur, a cleaning cost of $11 to $15.50 per kkg ($10 to $14 per ton) of cleaned coal would be appropriate currently. Bechtel Corporation has studied the economics of a 300 kkg (330 short ton) per hour plant suggesting a total capital cost of $131 million and a cleaning cost of $.78 per GJ ($0.82 per million Btu's), or $20.90 per cleaned kkg ($19 per cleaned short ton). The costs of both companies contain no profit margins, and Dow's cost is based on cleaning a Pennsylvania Lower Kittanning coal. Bechtel's design is based on using a Pittsburgh A bituminous coal. Dow indicates that, based on their design,

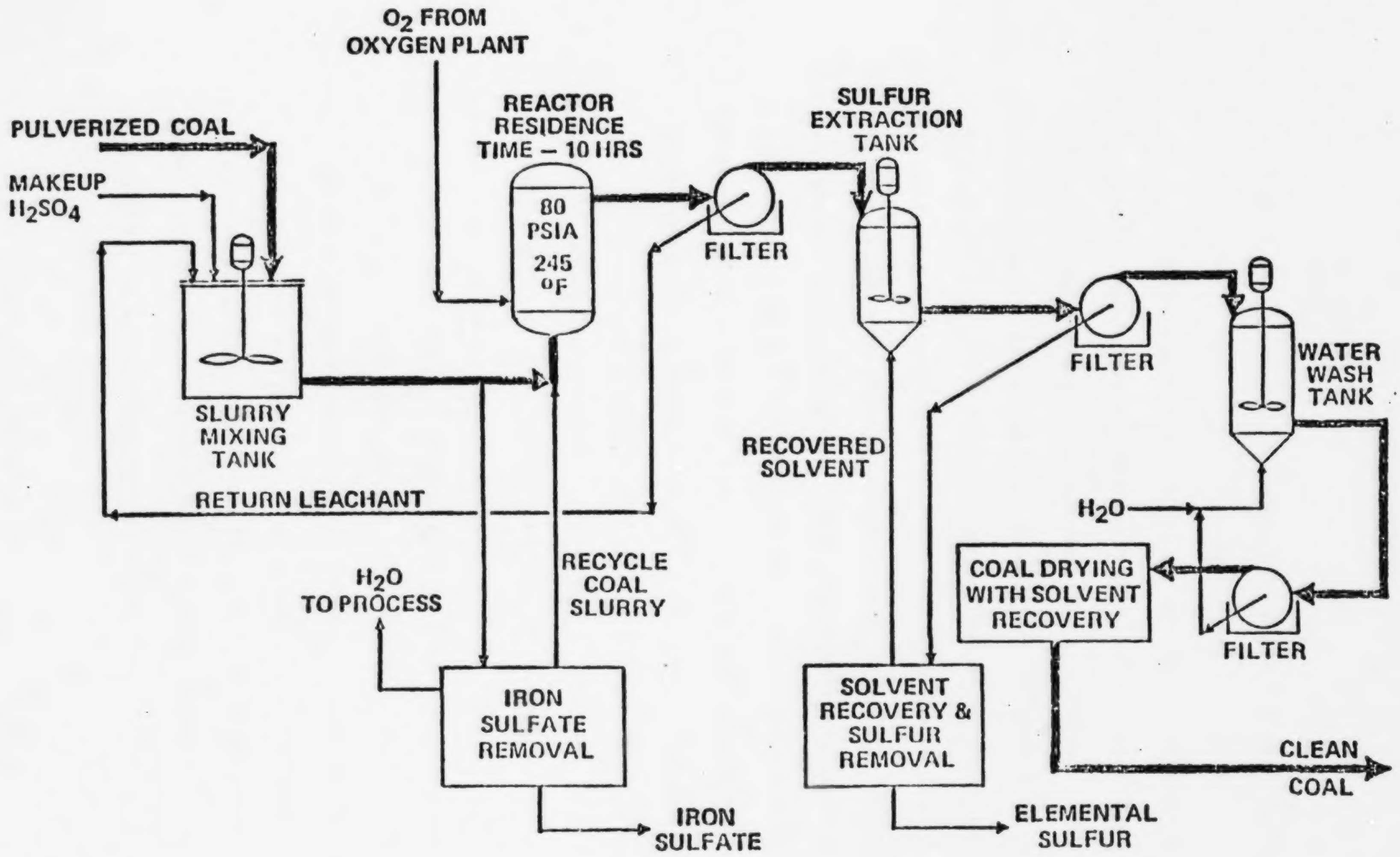
O_2 FROM OXYGEN PLANT
PULVERIZED COAL
MAKEUP H_2SO_4
REACTOR RESIDENCE TIME – 10 HRS
80 PSIA
245 °F
SULFUR EXTRACTION TANK
FILTER
SLURRY MIXING TANK
RETURN LEACHANT
RECOVERED SOLVENT
FILTER
WATER WASH TANK
H_2O
H_2O TO PROCESS
RECYCLE COAL SLURRY
COAL DRYING WITH SOLVENT RECOVERY
FILTER
IRON SULFATE REMOVAL
SOLVENT RECOVERY & SULFUR REMOVAL
CLEAN COAL
IRON SULFATE
ELEMENTAL SULFUR

FIGURE 4-1

MEYERS/TRW PROCESS FLOW DIAGRAM

the process can achieve a 90 percent Btu recovery, while Bechtel indicates 98 percent Btu recovery.

The Meyers process is one of the more troublesome chemical cleaning processes from an environmental standpoint. It uses organic solvents in contact with process wastes to extract the elemental sulfur. A portion of the solvent is left in the cleaned coal. The waste products of the process--ferrous sulfate, sulfuric acid, and physical cleaning refuse--have to be disposed of properly with pH adjustment. This refuse is obviously much more acidic than just physical cleaning refuse alone. Internally, the process must use a closed water circuit with solvent recovery to avoid further effluent problems. The Meyers process probably could be commercial in 5 to 6 years. An 8 ton per day pilot plant is currently being built, which should provide scale-up information.

4.2.2.2 Battelle Hydrothermal. The Battelle process (Battelle Memorial Institute, 1977) leaches - 149 m + 74 m (-100 + 200 mesh) coal with sodium and calicum hydroxide solutions at elevated temperatures and pressures, 98°C to 170°C (200°F to 340°F) and 1.55 to 17.25 MN/m^2 (225 to 2500 psia). The process removes up to 99 percent of the mineral sulfur and has demonstrated 24 to 72 percent organic sulfur removal, depending on the specific coal processed. Btu recovery ranges from 75 to 90 percent, depending on process operation. Figure 4-2 indicates the process layout and unit operations. The capital cost of the process suffers due to the elevated

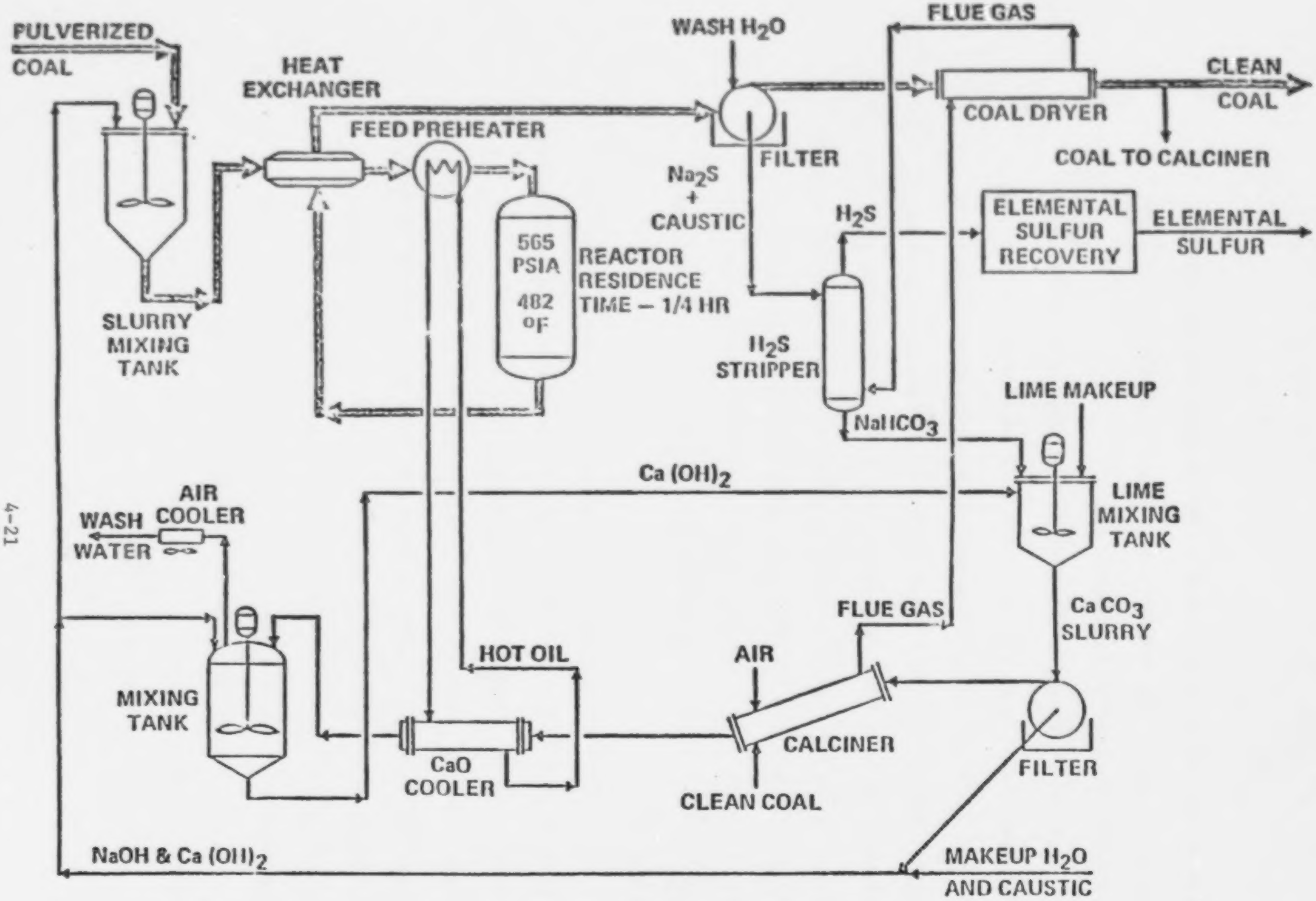
PULVERIZED COAL
HEAT EXCHANGER
FEED PREHEATER
WASH H_2O
FLUE GAS
CLEAN COAL
COAL DRYER
FILTER
COAL TO CALCINER
Na_2S + CAUSTIC
H_2S
ELEMENTAL SULFUR RECOVERY
ELEMENTAL SULFUR
565 PSIA
482 °F
REACTOR RESIDENCE TIME – 1/4 HR
SLURRY MIXING TANK
H_2S STRIPPER
LIME MAKEUP
$NaHCO_3$
$Ca(OH)_2$
LIME MIXING TANK
AIR COOLER
WASH WATER
$CaCO_3$ SLURRY
FLUE GAS
HOT OIL
AIR
MIXING TANK
CALCINER
CaO COOLER
FILTER
CLEAN COAL
NaOH & $Ca(OH)_2$
MAKEUP H_2O AND CAUSTIC

FIGURE 4-2

BATTELLE PROCESS FLOW DIAGRAM

temperatures and pressures used in the system, and the need for leachant regeneration equipment to close the process water loop, preventing the loss of leachant.

Battelle currently feels that an operating cost of $19.80 to $27.50 per kkg ($18 to $25 per short ton) of cleaned coal or about $.95 per GJ ($1.00 per million Btu) is a good estimate (Battelle Memorial Institute, 1977) based on the regeneration of leachant, 0.25 hour leaching time, and processing a lower Kittanning coal from 2.4 to 0.9 percent sulfur. Under these conditions, a capital cost of $134 to $145 million has been estimated for a 360 kkg (400 short tons) per hour plant, the cost depending on the coal to leachant ratio (2 to 1, or 3 to 1). No profit margin is included in these figures.

With leachant regeneration, internal process water loops are closed, so that the only water effluent is in the wet coal. Hydrogen sulfide (H_2S) is produced in the process, and protection against H_2S leakage would be necessary both from a processing and a safety viewpoint. The process is known to leach out many heavy metals in coal. Any effluents containing high concentrations of these metals may require special disposal. The Battelle hydrothermal process could be commercialized in 4 to 6 years.

4.2.2.3 Hazen Process. The Hazen process, shown in Figure 4-3, is a totally dry process. The process reacts iron pyrite with gaseous iron pentacarbonyl:

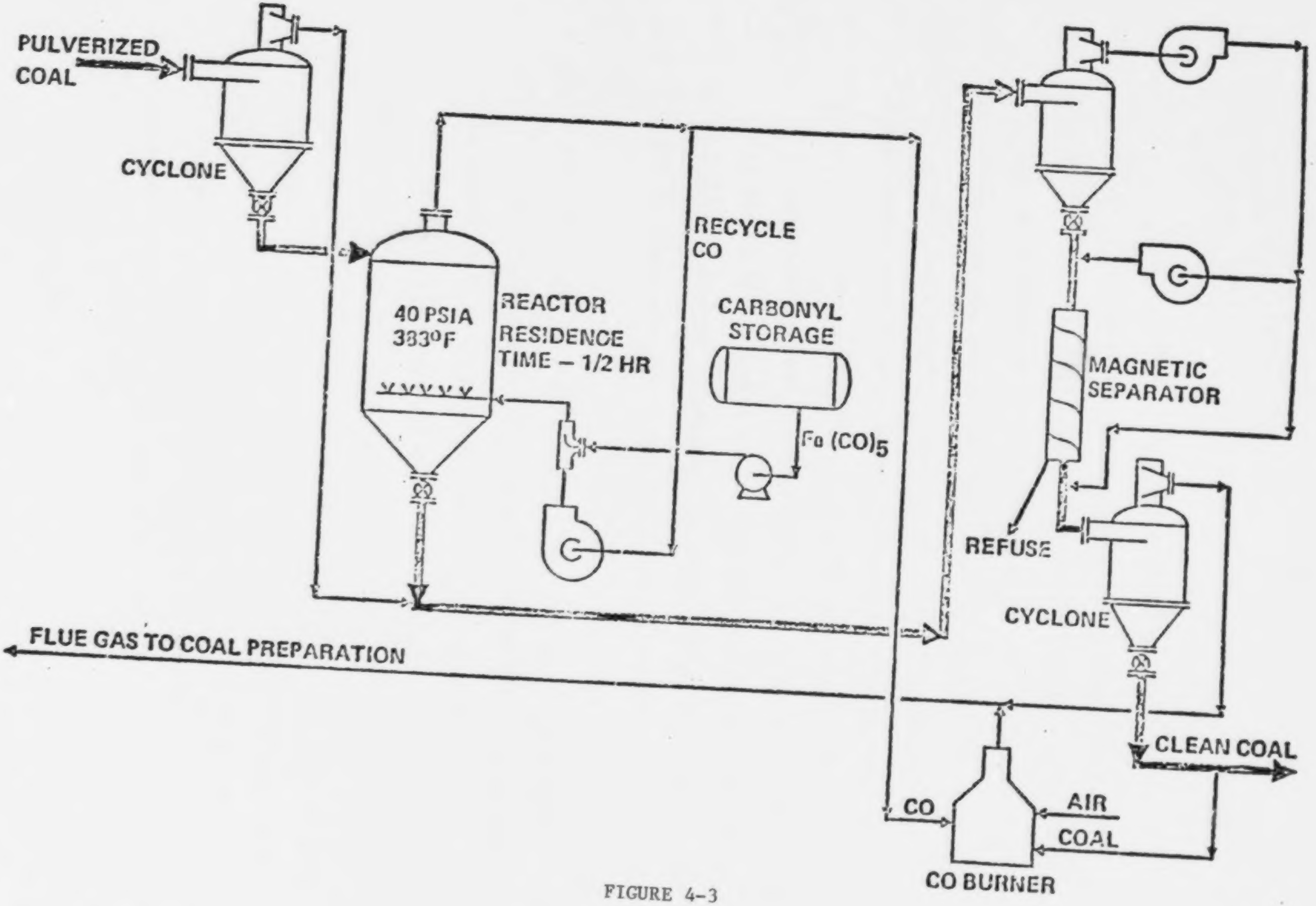
PULVERIZED COAL
CYCLONE
40 PSIA
383°F
REACTOR
RESIDENCE TIME – 1/2 HR
RECYCLE CO
CARBONYL STORAGE
Fe (CO)5
MAGNETIC SEPARATOR
REFUSE
CYCLONE
CLEAN COAL
FLUE GAS TO COAL PREPARATION
CO
AIR
COAL
CO BURNER

FIGURE 4-3

HAZEN PROCESS FLOW DIAGRAM

$$3\ FeS_2 + Fe(CO)_5 \longrightarrow 2\ Fe_2S_3 + 5\ CO$$

The Fe_2S_3 is much more magnetically susceptible, enabling it to be magnetically separated from the coal. Thus, this process can remove only mineral sulfur, and it requires very fine grinding of the coal to liberate the pyrite particles. This factor may restrict application of the Hazen process. The process is simpler than others, and uses fewer unit operations and process steps at mild temperatures and pressures. The process does have severe process monitoring requirements due to the use of highly toxic iron pentacarbonyl.

Results reported to date have been limited to coal ground to 1.19 mm (14 mesh) because there are no magnetic separators available to handle dry, fine-pulverized materials. Thus development of the process will be hindered.

Bechtel has estimated costs of a 300 kkg (330 short ton) per hour plant for a Pittsburgh bituminous coal at a capital cost of \$48 million, and operating and maintenance costs of about \$15.40 per kkg (\$14 per short ton) cleaned. They indicate a cleaning cost of \$.57 per GJ (\$.60 per million Btu), with a Btu recovery of 76 percent. Few aspects of Bechtel's design are specified; one is the $Fe(CO)_5$ cost. Hazen estimates its cost at \$.10 per pound with a consumption of 32 pounds per ton of coal (whether ROM or cleaned is not specified). Private vendor prices for $Fe(CO)_5$ run as high as \$3.30 per kkg (\$1.50 per pound). This higher price changes the cleaning costs dramatically.

Along with monitoring $Fe(CO)_5$ levels in the plant area, the disposal of the refuse will be of environmental concern. Problems will be similar to those of refuse from physical cleaning, except that Hazen refuse will create severe dusting problems because of its small particle size.

Hazen is considering a 0.9 kkg (1 ton) per day plant, so commercialization might be in 6 to 8 years.

KVB Process. This process shown in Figure 4-4, oxidizes sulfur components of dry pulverized -1.19 μm + 595 μm (-14 + 28 mesh) coal with NO_2 followed by caustic leaching to solubilize and remove the sulfur compounds formed in the oxidation step. The soluble sulfur compounds are mixed with lime to regenerate caustic and precipitate gypsum ($CaSO_4$), and iron oxides, which would be landfilled. The advantages of the KVB process are its claim to removal with oxidation; 87 percent with additional caustic leaching, the simplicity and low costs of dry oxidation; and the moderate temperatures, pressures, and vessel residence times. A problem in the system is the uptake of nitrogen by the coal.

Bechtel has developed cost information on the KVB process, based on the KVB patent and limited nonproprietary information (no literature is available and little bench-scale work has been done). Bechtel indicates a capital cost of $68 million for a 300 kkg (330 short tons) per hour plant with an operating and maintenance cost of $25 per kkg of cleaned coal ($23 per cleaned short ton). They indicate a cost of

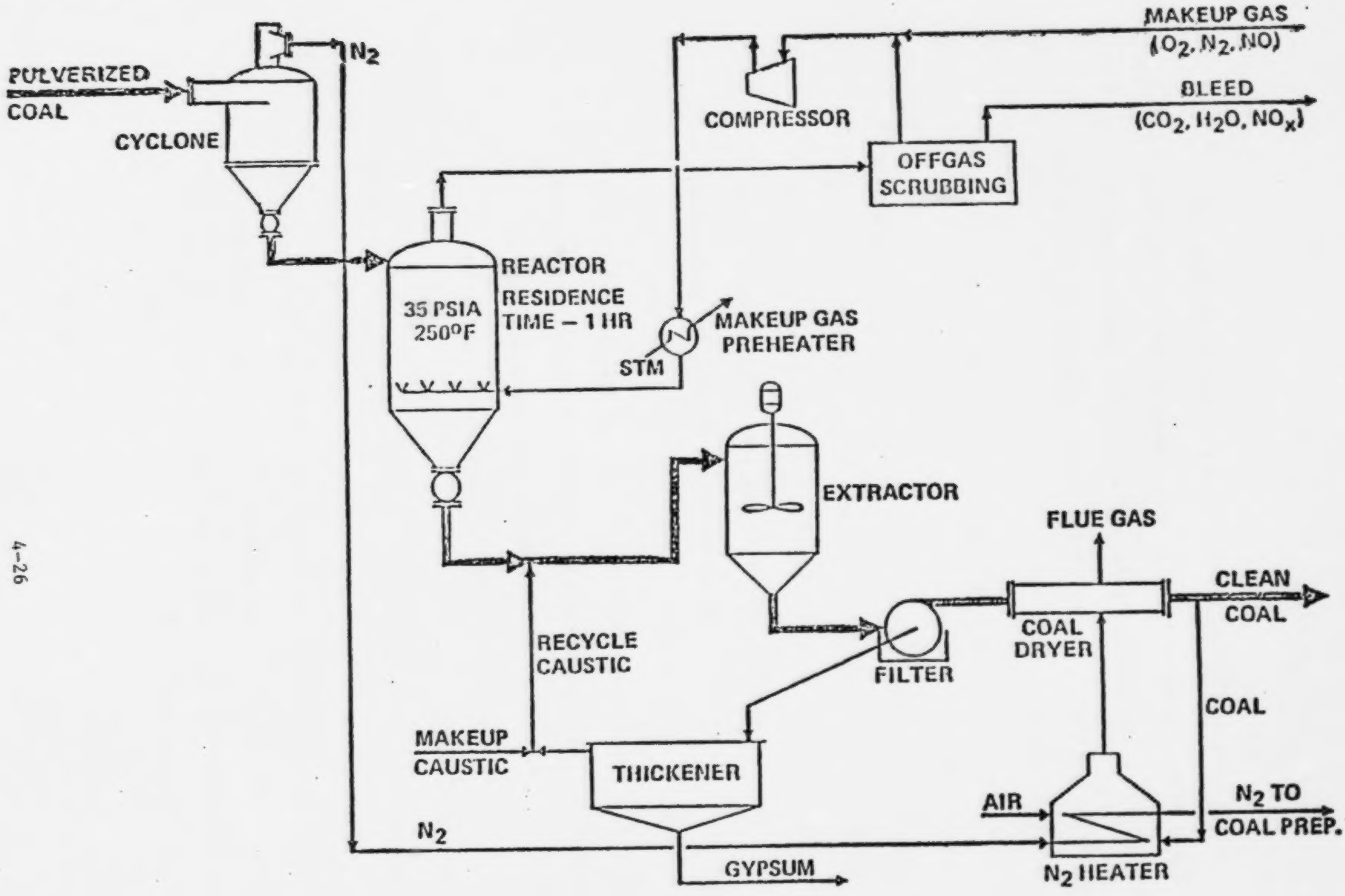
PULVERIZED COAL
CYCLONE
N_2
COMPRESSOR
MAKEUP GAS (O_2, N_2, NO)
BLEED (CO_2, H_2O, NO_x)
OFFGAS SCRUBBING
REACTOR
RESIDENCE TIME – 1 HR
35 PSIA 250°F
STM
MAKEUP GAS PREHEATER
EXTRACTOR
FLUE GAS
CLEAN COAL
COAL DRYER
FILTER
RECYCLE CAUSTIC
MAKEUP CAUSTIC
THICKENER
COAL
AIR
N_2 TO COAL PREP.
N_2
GYPSUM
N_2 HEATER

FIGURE 4-4

KVB PROCESS FLOW DIAGRAM

\$.93 per GJ (\$.98 per million Btu), for a Pittsburgh bituminous coal, with 90 percent Btu recovery.

Environmentally the KVB process poses one major problem; it is an NO_x producer. No information is available on expected effluent levels of NO_x. The other waste product is gypsum, for which established disposal technologies are available.

Ledgemont Oxygen Leaching (LOL). The LOL process (see Figure 4-5) is based on the following reaction:

$$FeS_2 + H_2O + 3.5O_2 \longrightarrow FeSO_4 + H_2SO_4$$

High temperatures and pressures must be used to speed the reaction rate for a commercially viable process. Strong oxidizing conditions in the reactor cause some coal loss and volatization in the reactor. This results in loss of heating value. The process has no significant organic sulfur removal capability. Sulfur is removed from the system by mixing the reaction products with lime, producing gypsum and iron oxides which would be landfilled. Kennecott Copper Company claims 95 percent pyritic sulfur removal in the LOL process, with 93 percent Btu recovery.

Dynatech and Bechtel have studied the economics of the LOL process. Dynatech's study gives an operating cost of \$7.60 per kkg (\$6.90 per short ton) cleaned, but no capital costs. Bechtel's study shows a capital cost of \$155 million for a 300 kkg (330 short tons) per hour plant with an operating cost of \$20.90 per kkg (\$19 per cleaned short ton) or \$.77 per GJ (.81 per million Btu). Dynatech

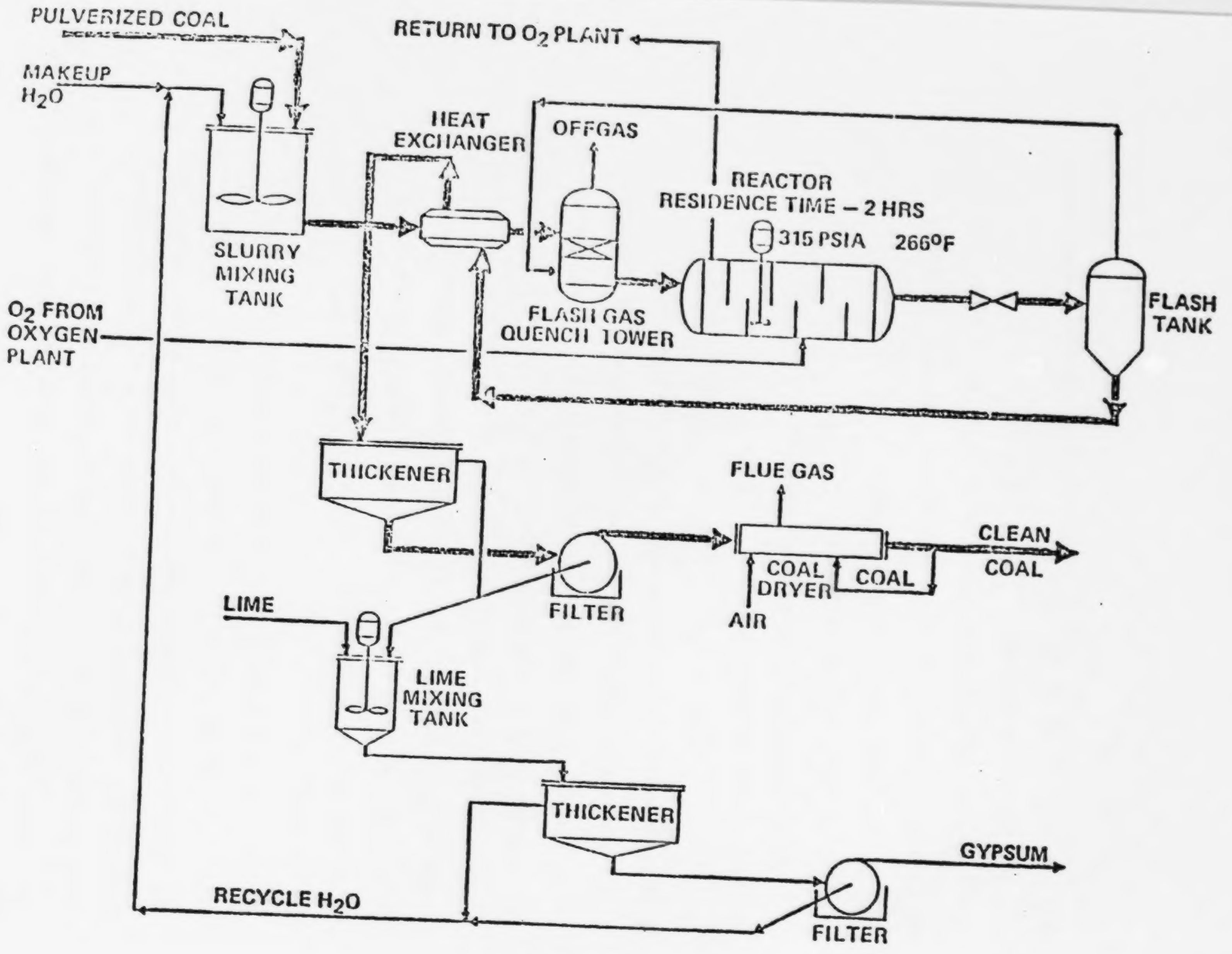
PULVERIZED COAL
MAKEUP H2O
RETURN TO O2 PLANT
HEAT EXCHANGER
OFFGAS
REACTOR
RESIDENCE TIME – 2 HRS
315 PSIA
266°F
SLURRY MIXING TANK
FLASH GAS QUENCH TOWER
FLASH TANK
O2 FROM OXYGEN PLANT
THICKENER
FLUE GAS
CLEAN COAL
COAL DRYER
COAL
FILTER
AIR
LIME
LIME MIXING TANK
THICKENER
GYPSUM
RECYCLE H2O
FILTER

FIGURE 4-5

LOL PROCESS FLOW DIAGRAM

does not indicate what coals were used as a design base, or what type of preparation facilities were included in the cost case. Bechtel indicates a Pittsburgh A bituminous coal pulverized to 80 percent minus 74 μm (200 mesh).

Bureau of Mines/ERDA. This process (see Figure 4-6) uses wet oxidation, employing air instead of oxygen as used by LOL. The process operates at higher temperatures and pressures than LOL, generating iron sulfates and sulfuric acid. Because of the extreme operating conditions, both pyritic and organic sulfur removal are claimed, and the process can be expected to show coal loss similar to the LOL process. Lime is used to convert iron sulfates to iron oxides and gypsum.

Bechtel has studied the economics of this process using a Pittsburgh bituminous coal. With pulverization facilities, grinding to 80 percent minus 74 μm (200 mesh), Bechtel estimates a capital cost of $130 million and an operating and maintenance cost of $20.90 per kkg of cleaned coal ($19 per cleaned short ton), or $.80 per GJ ($.84 per million Btu) with a Btu recovery of 94 percent. These costs are for a 300 kkg (330 short tons) per hour plant.

Environmentally, the process will be very similar to the LOL process. The process is under bench-scale development, so commercialization would be in about 6 to 9 years.

Dynatech Process. This process uses microbial action at 38°C (100°F) and 1 atmosphere pressure. There is little information but

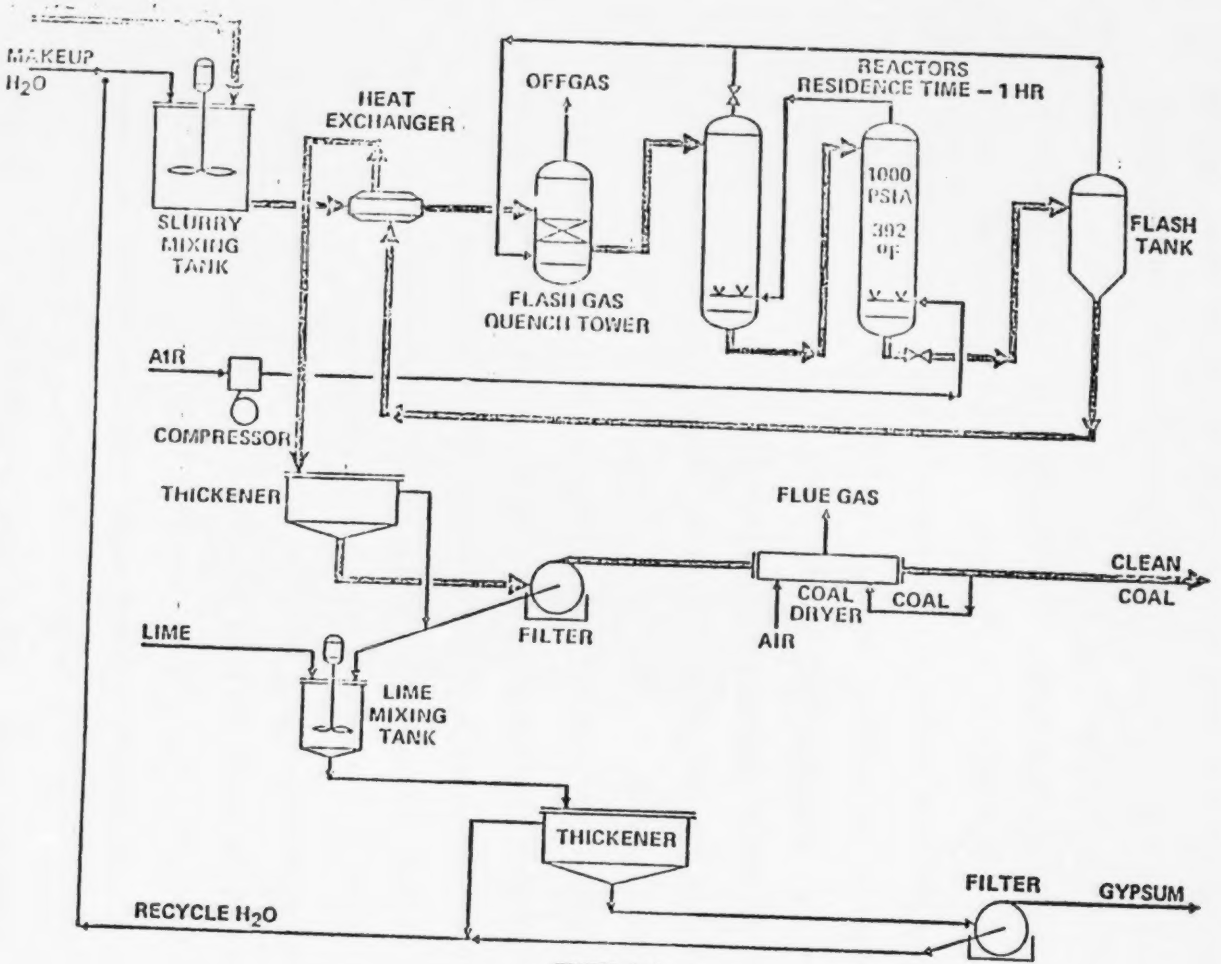
MAKEUP H_2O
SLURRY MIXING TANK
HEAT EXCHANGER
OFFGAS
FLASH GAS QUENCH TOWER
REACTORS RESIDENCE TIME – 1 HR
1000 PSIA
392 °F
FLASH TANK
AIR
COMPRESSOR
THICKENER
FLUE GAS
FILTER
COAL DRYER
COAL
AIR
CLEAN COAL
LIME
LIME MIXING TANK
THICKENER
FILTER
GYPSUM
RECYCLE H_2O

FIGURE 4-6

BOM/ERDA PROCESS FLOW DIAGRAM

Dynatech does indicate using minus 74 μm (200 mesh) washed coal; complete pyritic and some organic (amount unknown) removal; and gypsum, sulfuric acid, and elemental sulfur products. Dynatech has released limited cost data for a 300 kkg (330 ton) per hour plant with coal preparation facilities, indicating a cost of $4.15 per kkg ($4.05 per ton) of cleaned coal. Other details are not available.

General Electric Process. GE is developing a process that radiates coal with microwaves, gasifying the sulfur. Information is limited, but GE claims 52 percent reduction in pyritic and organic sulfur, and the possibility of reducing sulfur in most coals to 0.7 percent. Products of the process are H_2S; COS, SO_2; H_2O, CO_2 and traces of CH_4, C_2H_6, and H_2. GE's preliminary cost data for a 440 kkg (400 ton) plant claims a cost of $7.30 per kkg of cleaned coal ($6.60 per cleaned ton).

4.2.3 Solvent Refined Coal Process

Development of the SRC process originated in Germany prior to World War II, and was based upon the research of two German scientists, Pott and Brocke, who patented the basic process in 1932. Further development work was conducted in the U.S. from 1962 to 1965 by the Spencer Chemical Company, sponsored by the Office of Coal Research (OCR), Department of the Interior. The Spencer Chemical Company was subsequently acquired by Gulf Oil Corporation and development activity was continued by the Pittsburg and Midway Coal Mining Company, another Gulf subsidiary. A 50-ton per day SRC pilot plant is currently in operation at Ft. Lewis, Washington, under the sponsorship of the U.S. Department of Energy; and under the sponsorship of the electric utility industry, a 6-ton per day pilot plant is in operation on the site of an Alabama Power Company steam plant near Wilsonville, Alabama.

The SRC process involves dissolving of pulverized raw coal in a coal-derived solvent in a hydrogen atmosphere at elevated temperature and pressure, as shown in Figure 4-7. In the process, pulverized feed coal is first slurried with two or three parts of a solvent fraction that is generated internally in the process. This recycled solvent fraction has a boiling range of about 177°C (350°F) to Hydrogen is then added to the slurry of coal and solvent, and the mixture is preheated and transferred to a single-stage reactor or dissolver. In the reactor, the temperature is raised to 427°C (800°F) to 468°C (875°F)pressure is elevated to approximately 1700 psig. Under these conditions of temperature and pressure, approximately 93 percent of the carbonaceous material in the coal is dissolved during a residence time of approximately 30 minutes in the reactor. Approximately 60 percent of the organic sulfur in the coal is converted to hydrogen sulfide in the reactor, with hydrogen consumption of about 2 to 3 percent of the weight of the coal processed. The effluent from the reactor is then passed to a high pressure separator where the liquid and gas phases are separated. The liquid from the separator is next subjected to a mineral separator step where undissolved solids are

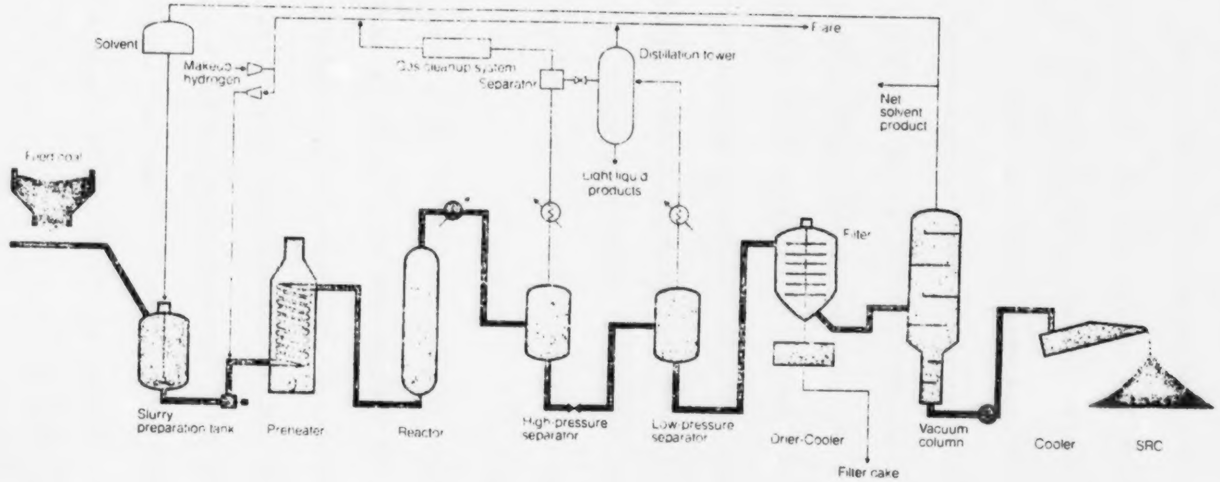
Solvent
Makeup hydrogen
Gas cleanup system
Separator
Flare
Distillation tower
Net solvent product
Feed coal
Light liquid products
Filter
Slurry preparation tank
Preheater
Reactor
High-pressure separator
Low-pressure separator
Drier-Cooler
Filter cake
Vacuum column
Cooler
SRC

FIGURE 4-7

SOLVENT REFINED COAL PROCESS

removed by filtration. The filtrate, from which the solids have been removed, is then flashed in a vacuum distillation column. Process solvent is recovered from the column and recycled to slurry the coal feed. The bottoms from the vacuum column form the solvent refined coal product which solidifies when cooled to about 177°C (350°F). The solid filter residue from the mineral separation step contains a substantial quantity of wash solvent as an absorbed liquid. This solvent is removed by passage of the residue through a rotary dryer where the solvent is extracted in vapor form, condensed to a liquid, and recycled to the process. The solid residue from the rotary dryer contains most of the mineral matter and some undissolved carbon. When the process is operated on a commercial scale, it is expected that this residue will be fed to a gasifier to produce hydrogen required in the process.

Evaluation of the SRC process at the Ft. Lewis, Washington facility has focused primarily on process-variable tests to generate information needed to establish optimal coal-processing conditions. Tests at this facility have utilized a Kentucky coal from Pittsburg and Midway's Colonial Mine (a mixture obtained from the No. 9 and No. 14 seams). SRC material produced at the facility has been stockpiled for use in burn tests at a 22-MW boiler at the Mitchell Plant Station of the Georgia Power Company.

Five major U.S. coals have been tested at the Wilsonville, Alabama, facility. The analyses of the coals tested is shown in

Table 4-5. The operating conditions used in the tests and the results produced (in terms of yield and sulfur content) are shown in Table 4-6. The typical analyses of the material produced by the SRC process with these five coals are shown in Table 4-7.

Extensive pulverization and combustion tests have been conducted on the product from the SRC process to provide information on utilization as a fuel in electric utility systems. In general, the material can be easily pulverized with minor modification required to the ball- and race or bowl-mill machinery commonly used in pulverized-fuel boilers. However, the pulverized SRC material has the unusual property of tending to agglomerate. Accordingly, it is necessary to redesign most burner systems (normally with water jacketing) to keep the temperature of the pulverized SRC at about 66°C (150°F) despite boiler windbox temperatures of 260°C (500°F) to 316°C (600°F). Additional burner changes involve the use of a venturi to control fuel flow and stabilize the burner flame (as opposed to conventional nozzle impellers which would be easily fouled by the SRC material).

In terms of burning characteristics, the SRC material ignites like an oil, but requires a longer burnout time (similar to an anthracite). In some tests, an improved boiler heat transfer rate has been observed when SRC material is utilized over that attained when coal is fired. (This is possibly attributable to the fact that SRC combustion does not produce a slag layer on furnace surfaces because of its low ash content.)

TABLE 4-5

TYPICAL ANALYSES OF COALS USED

Source					
State	Kentucky	Illinois	West Virginia	Illinois	Wyoming
Seam	No. 9 and 14	No. 6	Pittsburgh	No. 6	Roland-Smith
Mine	Colonial	Burning Star No. 2	Loveridge	Monterey	Belle Ayr
Company	Pittsburg & Midway Coal Mining Co.	Consolidation Coal Co.	Consolidation Coal Co.	Monterey Coal Company	Amax Coal Co.
Proximate Analysis (dry basis), wt%					
Volatile Matter	38.03	38.27	39.98	44.04	54.16
Fixed Carbon	53.04	50.93	51.74	45.81	38.07
Ash	8.93	10.80	8.28	10.15	7.77
Moisture	4.21	5.80	6.50	6.22	6.36
Heating Value, Btu/lb	13,060	12,602	13,856	12,215	11,307
Ultimate Analysis, wt%					
Carbon	72.94	70.94	75.71	64.80	67.95
Hydrogen	5.27	5.06	5.12	5.39	4.94
Nitrogen	1.14	1.25	1.32	1.20	1.06
Chlorine	0.13	0.09	0.11	0.07	0.01
Sulfur	3.07	3.23	2.63	4.25	0.62
Ash	8.93	10.80	8.28	10.15	7.77
Oxygen	8.52	8.63	6.83	14.14	17.65
Sulfur Forms, wt%					
Pyritic	1.12	1.03	0.89	1.14	0.06
Sulfate	0.10	0.15	0.04	0.19	0.03
Organic	1.85	2.05	1.70	2.92	0.53
Iron in Ash, wt%	17.36	10.25	8.61	11.86	7.28

TABLE 4-6

TYPICAL OPERATING CONDITIONS AND RESULTS

Feed Coal					
State	Kentucky	Illinois	West Virginia	Illinois	Wyoming
Seam	9 and 14	No. 6	Pittsburgh	No. 6	Roland-Smith
Mine	Colonial	Burning Star No. 2	Loveridge	Monterey	Belle Ayr
Conditions					
Coal Feed, MF, lb/hr	500	460	500	500	370
Coal in Feed Slurry, wt%	24	25	25	25	20
Gas Feed Rate, scfh	5600	5000	5000	10,000	10,000
Hydrogen in Feed Gas, vol%	86	88	87	86	86
Pressure, psig	1700	1800	1700	2400	2400
Temperature, °F	830	820	855	855	825
Results					
Conversion, % of MAF Coal	92	90	91	95	88
Hydrogen Consumed, % of MAF Coal	2.2	2.3	2.2	3.1	3.2
Yields, % of MAF Coal					
Solvent Refined Coal	66	66	74	52	50
Organic Liquids					
Boiling below 350°F	8	3	1	4	3
Boiling 350-800°F	6	12	7	24	17
Gas	11	11	11	13	14
Water	1	1	3	4	8

TABLE 4-7

TYPICAL ANALYSES OF SOLVENT REFINED COAL

Feed Coal					
State	Kentucky	Illinois	West Virginia	Illinois	Wyoming
Seam	9 and 14	No. 6	Pittsburgh	No. 6	Roland-Smith
Mine	Colonial	Burning Star No. 2	Loveridge	Monterey	Belle Ayr
Proximate Analysis (dry basis), wt%					
Volatile Matter	70.6	68.5	56.6	72.1	51.7
Fixed Carbon	29.3	31.4	43.3	27.8	48.2
Ash	0.1	0.1	0.1	0.1	0.1
Heating Value, Btu/lb	15,700	15,500	15,900	15,800	15,900
Ultimate Analysis, wt%					
Carbon	87.2	88.5	87.9	87.1	88.4
Hydrogen	5.6	5.3	5.7	6.0	5.6
Nitrogen	1.8	1.9	1.6	1.9	1.7
Chlorine	Trace	Trace	Trace	--	--
Sulfur	0.8	0.8	0.9	0.8	0.1
Ash	0.1	0.1	0.1	0.1	0.1
Oxygen	4.5	3.4	3.8	4.1	4.1
Sulfur Forms, wt%					
Pyritic	0.05	0.03	0.01	0.07	0.01
Sulfate	0.00	0.06	0.02	0.01	0.00
Organic	0.75	0.68	0.86	0.75	0.11
Melting Point, ^{o}F	360	380	340	300	335

The normal nitrogen content of the SRC material can range from 1.5 to 1.9 percent compared with 1.0 to 1.2 percent in the natural coal. This is due to the fact that the SRC process does not remove any of this constituent from the coal. However, more thorough combustion testing is required, particularly at higher more representative furnace temperatures, before it can be determined if this characteristic of the process would present any special problem with respect to NO_x emissions.

Although specific current costs estimates have not been published for the SRC process, several general statements have been offered by the industry based on estimates made by Southern Company Services for two new power plants (one with raw coal firing and scrubbing, and the other fired with SRC material).

The industry has stated that if one takes into account the difference in expected "forced outage rates" in the two options, achievement of the same electrical system reliability would require a greater reserve capacity for the scrubber option. Industrial representatives have further stated that the energy used in connection with the scrubber operation will require greater generating capacity for the scrubber option to achieve the same net electrical output. Further, the capital requirements per unit of total output are said to be less for the SRC option because of claimed inherent savings associated with the quality and heating value of the fuel (i.e., less fuel storage area is required, the boiler can be smaller, the pulverizers can be smaller, the ash storage area can be significantly reduced if not eliminated, etc., and no provisions are required for scrubber wastes). The industry has stated that when these factors are taken into account, the capital requirements for an SRC-fired generating plant will be only about 60 to 70 percent of those for a coal-fired plant equipped with scrubbers. However, much of this capital difference will be required by others for investment in the SRC refinery itself, although this will reduce the huge capital burden of the utility industry. SRC firing is also claimed to bring about reductions in operating cost since cost savings are claimed because there is no need to provide for scrubber reactants, for personnel and energy to operate and maintain the scrubber system, and for disposal of scrubber wastes.

4.2.4 Summary and Conclusions

While physical and/or chemical coal cleaning has some potential to extend the range of usable coals under the current NSPS, the impact is much less when a new, more stringent NSPS is considered. Figure 4-8 graphically projects the reduction in sulfur content based on four cleaning scenarios and plots them against the percent of mines sampled with coal sulfur content less than or equal to industrial percent sulfur. An alternative might be the use of coal cleaning with another SO_2 control system such as FGD. This is especially the case with physical coal cleaning since it is a low-cost, well established technology that provides a consistent product in terms of

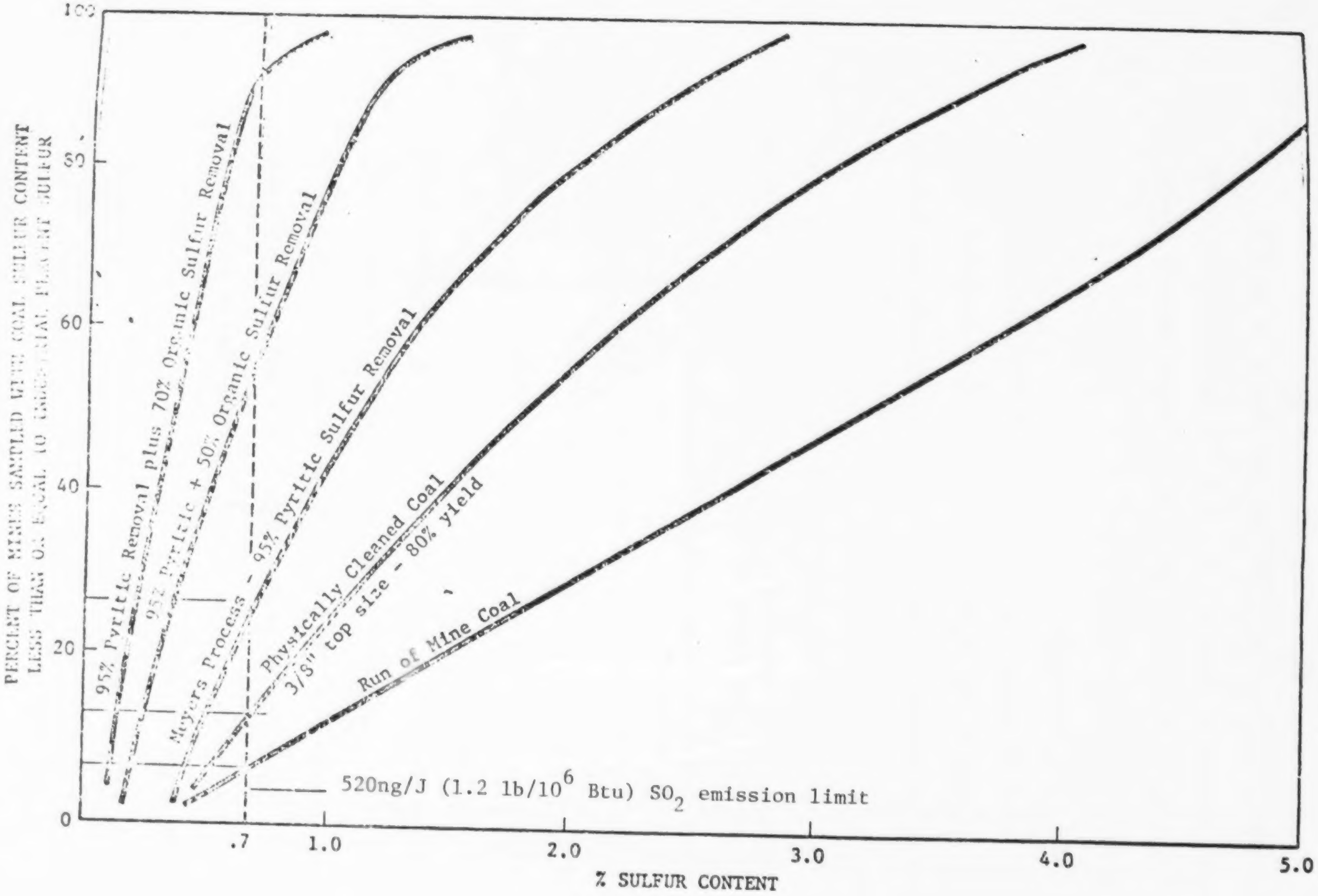

FIGURE 4-8

PERCENT OF UNITED STATES BITUMINOUS COAL CLEANABLE TO A GIVEN SULFUR CONTENT FOR VARIOUS CLEANING SCENARIOS

*Based on U.S. Bureau of Mines Data

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moisture, ash and caloric value and requires little or no R&D. The chemical processes, however, are still in the development stage. The projected costs and sulfur removal for a number of coal cleaning processes are summarized in Table 4-8.

4.3 Fluidized Bed Combustion

The removal of sulfur compounds can be achieved during the combustion process by application of fluidized bed combustion (FBC). This process has potential advantages over conventional coal-burning processes:

- The ability to burn a large variety of fuels
- The capability of directly controlling the emission of sulfur oxides (SO_x), as a step in the combustion process
- The potential for simultaneous reduction in emission of nitrogen oxides (NO_x)
- Small system size per given capacity
- High thermal efficiency (heat transfer rate)
- Projected lower capital and operating costs.

4.3.1 Overview

Fluidized bed combustion involves the burning of a fuel (coal) in a bed of inert ash and/or an active sorbent for the control of sulfur oxide emissions. The bed is fluidized (i.e., the solid particles of coal, ash, and sorbent are held in suspension) by air injected at controlled rates through an air distributor plate that supports the bed material.

TABLE 4-8

MAJOR COAL CLEANING PROCESS CONSIDERATIONS

PROCESS	PLANT SIZE BASIS short ton per hour	COSTS			SULFUR REMOVAL		Btu RECOVERY %
		CAPITAL $\$10^6$	PROCESSING $/ton	PROCESSING $\$/10^6$ Btu	PYRITIC %	ORGANIC %	
Physical[a]	500	9.0	4.27	.18	35-70	-	80-95
TRW/Meyers[a]	380	145	10 -14	.82	95	-	90
Battelle Hydrothermal	400	134 -145	18 -25	1.00	99	24-72	75-90
Hazen	330	48	14	.60	80	-	76
KVB	330	68	23	.98	99	13	90
LOL	330	150	19	,81	95	-	93
BOM/ERDA	330	130	19	.84	99	15	94
Dynatech	330	-	4.05	-	-	-	-
GE	400	-	6.60	-	50 Combined		-

---

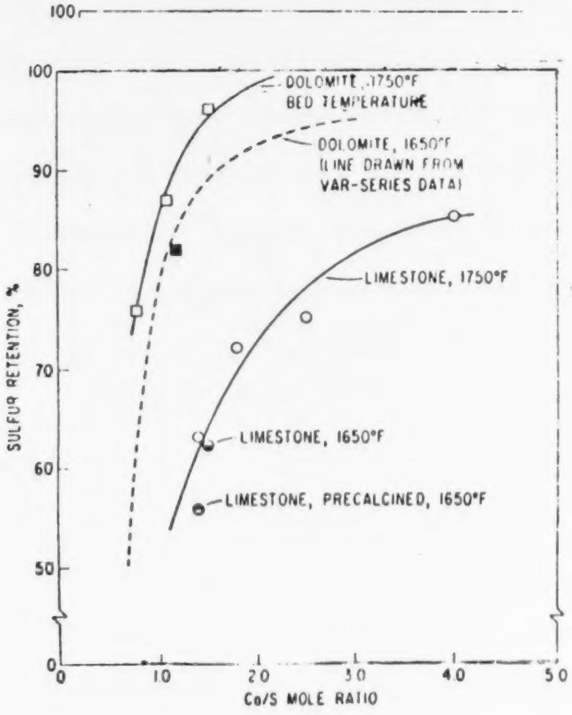
[a] See text for basis of costs and other data.

[b] Includes capital charge plus operating and maintenance costs, basis for costs are cleaned coal.

The two major categories of fluidized bed combustion are atmospheric and pressurized fluidized bed combustion (AFBC and PFBC). In both types of FBC, the reactive bed materials generally employed and most thoroughly studied are calcined dolomite (MgO CaO) or calcined limestone (CaO). These calcium compounds are calcined under heat, yielding metallic oxides that react the sulfur oxides from the coal combustion to form sulfates and, hence, the sulfur oxides are removed from the flue gas.

The amount of SO_2 removed by a CaO bed is not limited by thermo-dynamic equilibrium. The partial pressure of SO_2 in equilibrium with CaO, $CaSO_4$, and O_2 is 1.25×10^{-7} atm at 902°C (1656°F), or about 0.125 ppm, This very low value is not achieved in practice because equilibrium is not reached. Relatively high SO_2 removal has been obtained in experimental units by using greater than stoichiometric quantities of CaO. EPA sponsored research has demonstrated that the FBC can achieve more than 90% sulfur removal (see Figure 4-9). Furthermore, developmental PFBC units have burned moderately high-sulfur coals, and achieved 0.3 lbs SO_x/million Btu in the flue gas stream. For high sulfur removal rates (90% or greater) Ca/S ratios of 2 or greater are required, which leads to large quantities of spent limestone. In a once-through system design this material must be disposed of in an environmentally acceptable manner. Research on methods of regenerating the spent bed material is in progress. The excess CaO required for efficient SO_2 removal complicates the regeneration processes by increasing the

- Sulfur-retention capabilities of additives compared, molar basis



Source: U.S. EPA, 1976.

FIGURE 4-9

CONTROL OF ATMOSPHERIC POLLUTION BY FBC

quantity of material to be processed. For these reasons considerable research is being devoted to keeping the Ca/S ratio requirement at a minimum. A detailed discussion of factors and data relating to SO_2 removal in a FBC is presented in Appendix A.

The solid wastes generated by the FBC process consist of ash and spent limestone or dolomite particles. This granular matter is withdrawn from the bed or removed as finer particulate matter from the effluent gases by the final dust collection. The sorbent requirements and disposal problems can be reduced by a regeneration process. When a regeneration process is utilized, sulfated sorbent is withdrawn from the bed and regenerated to produce an SO_2 or H_2S rich stream which is subsequently fed to a conventional sulfur recovery operation producing sulfur or sulfuric acid. The regenerated sorbent is then returned to the bed.

These FBC wastes are of two types: ash and sulfur containing or desulfurization waste. This is the case with conventional combustion and FGD or coal cleaning as well as FBC. The desulfurization wastes from AFBC and PFBC generate a dry material consisting of calcium sulfate; calcium carbonate; calcium oxide; and, in some cases, magnesium oxide.* Several other minor constituents are also present. While the wastes from FBC are of a magnitude similar to FGD, because of the differences in physical characteristics and the higher calcium sulfite content of the FGD wastes, the disposal of FBC wastes is expected to be of a somewhat lesser magnitude. Because the waste is dry, reclamation of disposal land should be possible with minimal preparation. The FBC wastes are also expected to have lower potential for trace element toxic effects; however, a further investigation in the area of trace elements and leachate effects will be required to verify these expectations. Additional research in waste utilization and sorbent regeneration will also aid the development of the FBC.

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*Percentage depends on amounts of limestone and/or dolomite.

4.3.2 FBC Systems

Fluidized bed combustion systems may be categorized according to the presence or absence of heat transfer surfaces in the bed (or the excess air levels) and the operating bed pressure. The three basic systems are: combustion at atmospheric pressure (tubes in the bed and excess air levels of 15 to 25 percent), pressurized bed (tubes in the bed and excess air levels of 15 to 25 percent) and adiabatic pressurized combustion (no tubes, heat exchangers, hence no Q change, in the bed and excess air levels of 300 percent). The low excess air pressurized system can be further subdivided into those systems using air and those using water as the working fluid in the tubes in the bed. The system descriptions and flow diagrams presented here are subdivided on the basis of the combustion pressure alone. The descriptions are for a generic AFBC and PFBC.

4.3.2.1 Generic Atmospheric FBC of Coal. A schematic flow diagram for a generic atmospheric FBC unit is presented in Figure 4-10. Atmospheric fluidized-bed combustion occurs in the temperature

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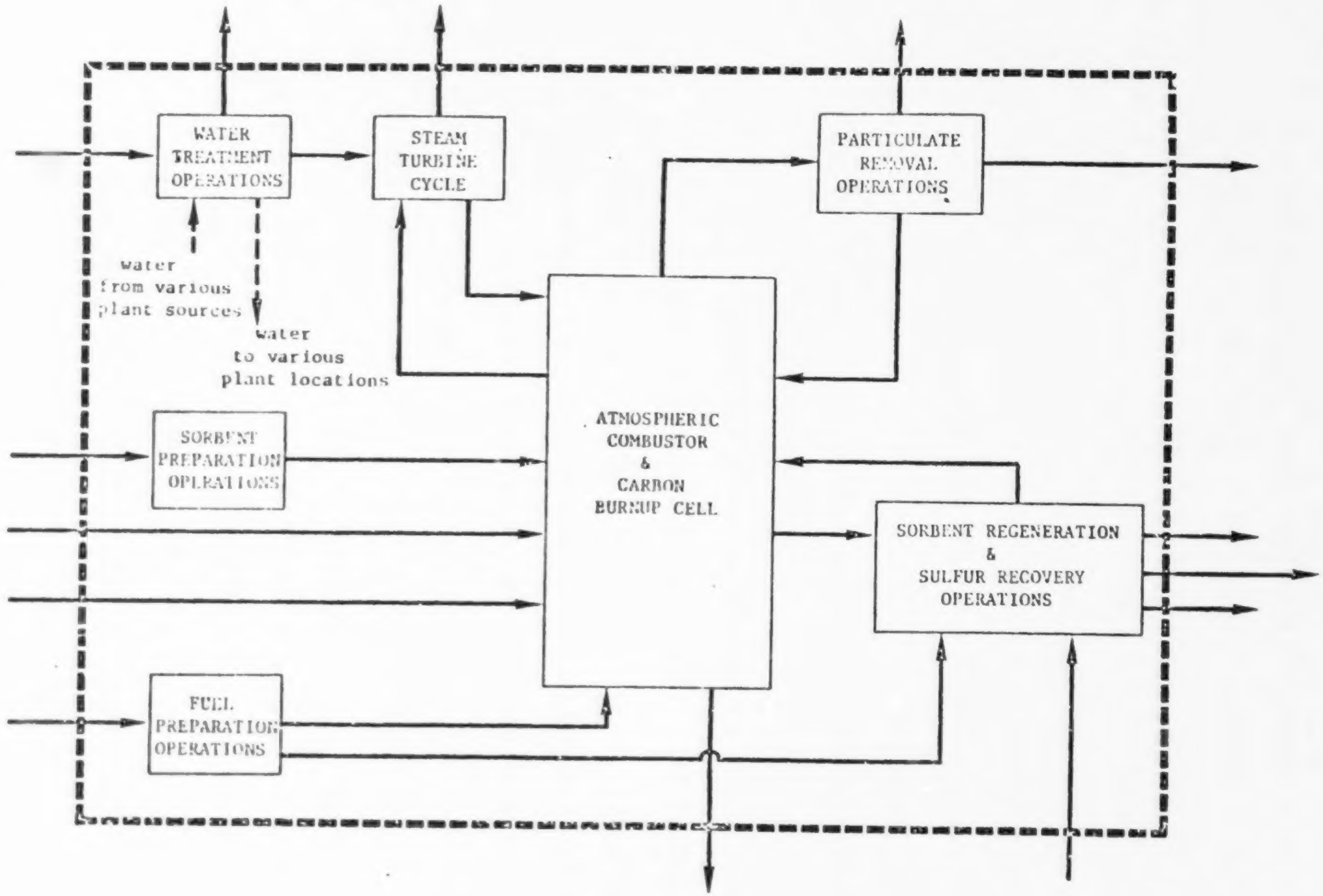
WATER TREATMENT OPERATIONS
STEAM TURBINE CYCLE
PARTICULATE REMOVAL OPERATIONS
water from various plant sources
water to various plant locations
SORBENT PREPARATION OPERATIONS
ATMOSPHERIC COMBUSTOR & CARBON BURNUP CELL
SORBENT REGENERATION & SULFUR RECOVERY OPERATIONS
FUEL PREPARATION OPERATIONS

FIGURE 4-10

GENERIC PROCESS FLOW SHEET FOR CATEGORY I ATMOSPHERIC FBC OF COAL range of 788°C to 843°C (1450°F to 1550°F) with excess air values of 15 to 25 percent, at normal atmospheric pressure. Steam produced in the bundles and/or water walls located within the fluidized region is converted to electrical energy in a conventional steam turbine cycle. Tube bundles immersed within the bed are expected to result in an increased heat transfer over conventional boilers due to the constant agitation of the bed material and gases in control with the steam tubes. Typical fluidization velocities are 6 to 8 ft/sec.

Most of the ash present in the coal feed is normally elutriated from the bed and must be removed (along with attrited limestone and other particulates) before release of flue gas to the atmosphere. Since this ash may be high in carbon content, its direct disposal would result in a lowered combustion efficiency. To remedy this problem, the atmospheric unit can employ a carbon burnup cell (CBC), a separate high-temperature, high-excess-air bed to which the collected ash is fed and combusted. Products from the CBC would then undergo an additional particulate removal operation prior to flue gas release to the atmosphere. Alternatively, reinjection of collected ash back into the combustor may be adopted to improve combustion efficiency. It should be noted that the "particulate removal operation" blocks indicated in the generic flow sheets are general and may include combinations of cyclones, filters, baghouses, precipitators, and other devices. Normally a cyclone or series of cyclones is employed initially to remove coarse particles from the flue gas, while final cleanup is accomplished by other methods.

The generic units are intended to be representative of anticipated commercialized systems and, as such, it is projected that there will be on-site fuel preparation, sorbent preparation, and sulfur recovery operations.

The fuel preparation operations involve drying, size reduction and size classification. These operations are similar to those found in conventional systems. The sorbent preparation operations consist of size reduction and classification of raw material and should pose no new problems. Similarly, the steam turbine cycle and water treatment operations are similar to those of conventional steam turbine systems.

Available data from pilot and bench scale studies indicate that generally 90 percent sulfur retention can be obtained with a Ca/S ratio of 3 to 4 (Figure 4-11). While the data from small scale units are promising, these experimental units are orders of magnitude smaller than proposed commercial units. Extrapolation of pilot and bench-scale studies may not be reliable for estimating SO_2 emissions for larger demonstration and commercial scale units because scale-up of gas-solids interactions is especially difficult. The DOE and EPA development programs will be collecting these data as larger pilot plants and demonstration plants come on stream. In the event that SO_2 control is found to be poor, it can be improved by deeper beds or lower superficial velocity.

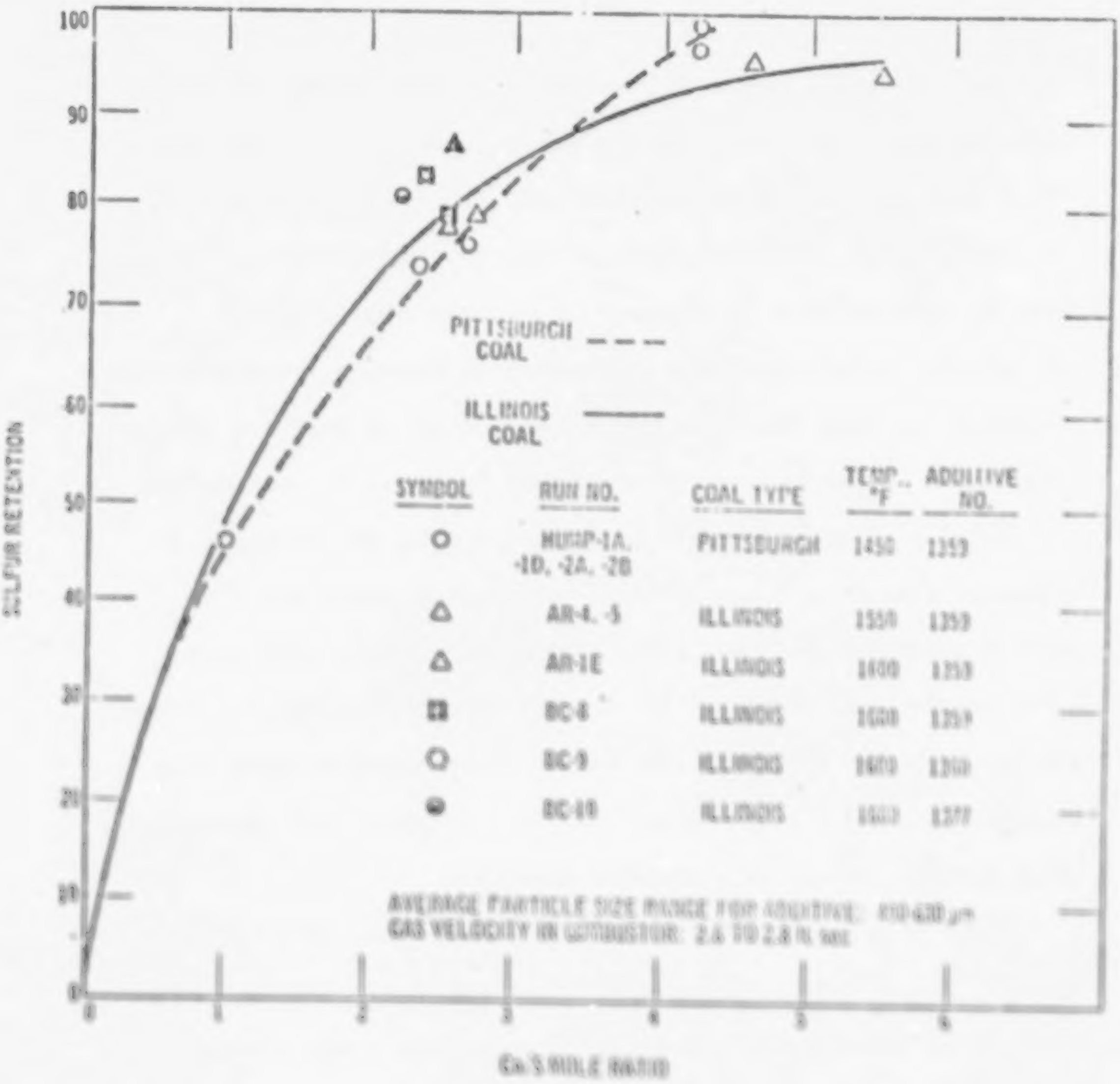

FIGURE 6-11

EFFECT OF Ca/S MOLE RATIO ON SULFUR RETENTION

The additional limestone requirement to meet reduced SO_2 levels would aggravate the sorbent supply and disposal problems and impact FBC process costs in an undetermined way. Moreover, since much of the limestone is elutriated from the bed, the load on the particulate handling systems could be expected to increase substantially. Attempts to improve limestone utilization by crushing and reinjection could further complicate the particulate collection problem. Process information needed to gauge these effects is currently unavailable.

4.3.2.2 Generic Pressurized, Combined Cycle FBC of Coal. A schematic flow sheet for a generic, pressurized, combined-cycle unit is presented in Figure 4-12. As stated earlier, pressurized units are further subdivided in terms of their heat transfer surfaces, for instance, the adiabatic FB (Figure 4-13) generates steam from a waste heat boiler after the gas turbine in contrast to Figure 4-12 which utilizes in-bed heat transfer surfaces.

Combustion for the pressurized bed again occurs in a fluidized bed of fuel, ash and sorbent with excess air ranges similar to those found in the atmospheric boiler and at temperatures approximately 93°C (200°F) higher. Pressure within the combustor, however, is maintained at a design value of 4 to 11 atmospheres, resulting in a dramatic reduction in combustor size requirements and, thus, combustor cost. The elevated pressure of the PFBC allows the use of deeper beds, resulting in greater combustion efficiency (99 percent as compared with 98.5 for AFBC).

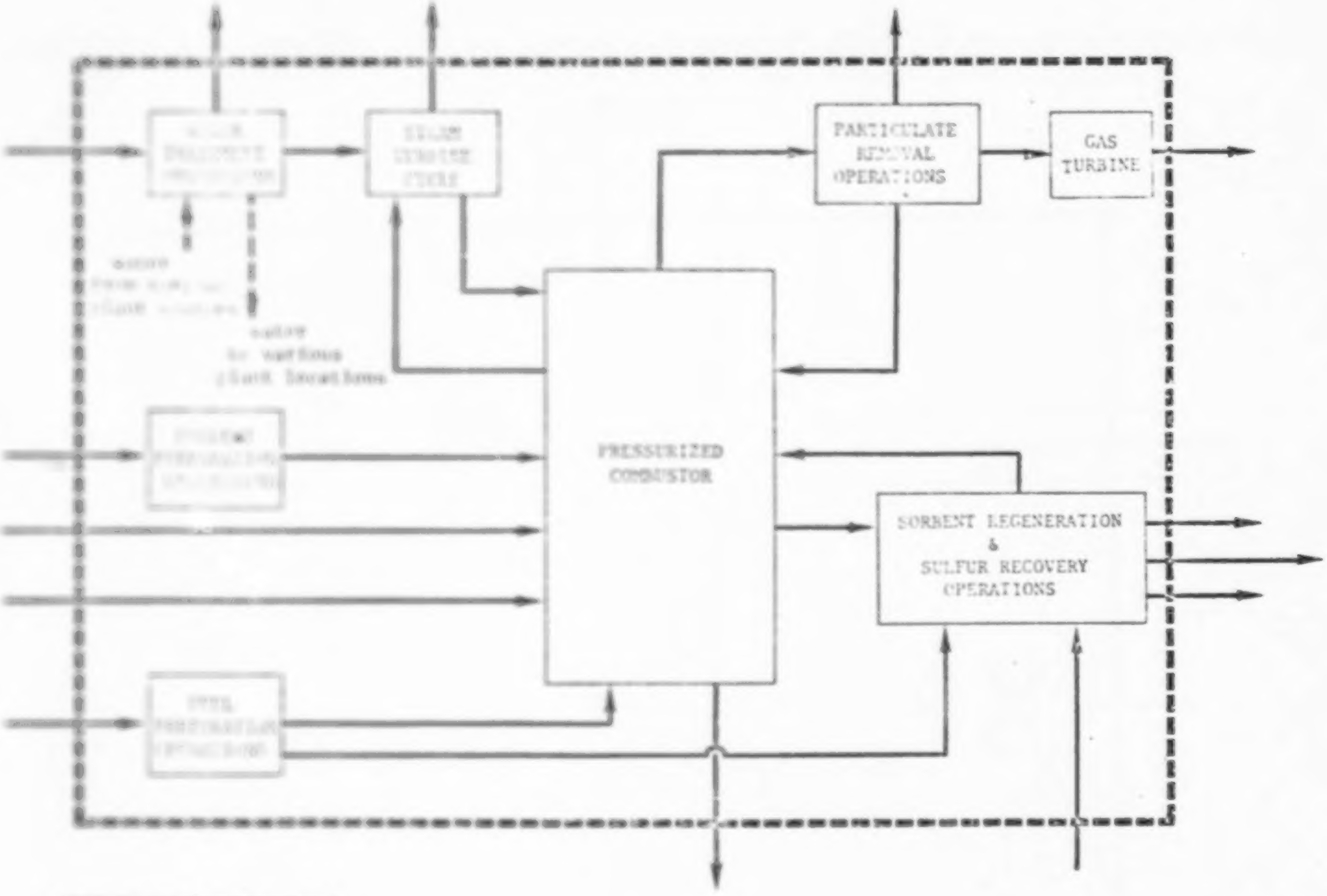
STEAM TURBINE CYCLE
water to various plant locations
FUEL PREPARATION OPERATIONS
PARTICULATE REMOVAL OPERATIONS
GAS TURBINE
PRESSURIZED COMBUSTOR
SORBENT REGENERATION & SULFUR RECOVERY OPERATIONS

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FIGURE 4-12

GENERIC PROCESS FLOW SHEET FOR CATEGORY II PRESSURIZED, COMBINED CYCLE FBC OF COAL

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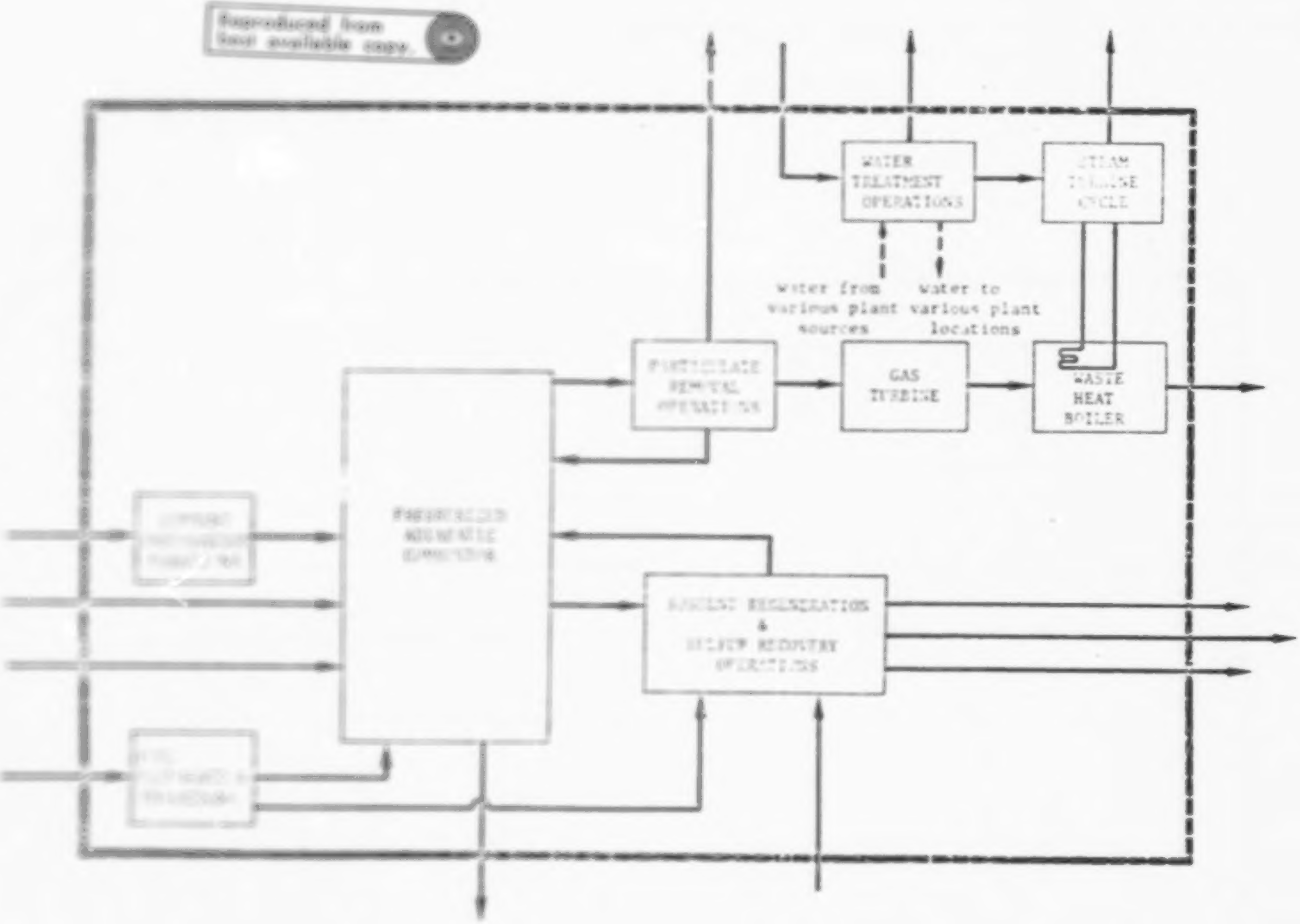
WATER TREATMENT OPERATIONS
STEAM TURBINE CYCLE
water from various plant sources
water to various plant locations
PARTICULATE REMOVAL OPERATIONS
GAS TURBINE
WASTE HEAT BOILER
PRESSURIZED ADIABATIC COMBUSTOR
SORBENT REGENERATION & SULFUR RECOVERY OPERATIONS

FIGURE 4-13

GENERIC PROCESS FLOW SHEET FOR CATEGORY III - PRESSURIZED, COMBINED CYCLE FBC OF COAL (ADIABATIC COMBUSTOR)

In contrast, the combined cycle adiabatic combustion utilizes about 300 percent excess air at 816°C to 982°C (1500°F to 1800°F) and four atmospheric pressure. The system will require a somewhat larger combustion than the other pressurized system.

The primary power for the adiabatic combustion (about 80 percent) will be from the gas turbine and the remainder from the waste heat steam turbine generator. The pressurized (nonadiabatic) combined cycle system would develop the primary generating power from the steam cycle and secondary power from the gas turbine.

The fuel and sorbent preparation, the steam turbine cycle and water treatment for the pressurized system are similar to corresponding atmospheric operations. The particle control systems for the combined cycles must maintain levels sufficient to meet gas turbine requirements, which are generally more stringent than requirements for the atmospheric particle control system, which must meet current control standards.

In pressurized fluidized bed combustion, small pilot plant data have shown that sulfur reductions of 90 percent may be obtained on high sulfur Eastern coals with the use of dolomite sorbent (Figure 4-14). The activity of limestone is less than that of dolomite under pressurized conditions and it is completely inactive at low temperature turndown conditions. Unless some way of increasing its activity can be found, limestone will not be used in a PFB combustor to achieve high level sulfur reduction because of excessive stone

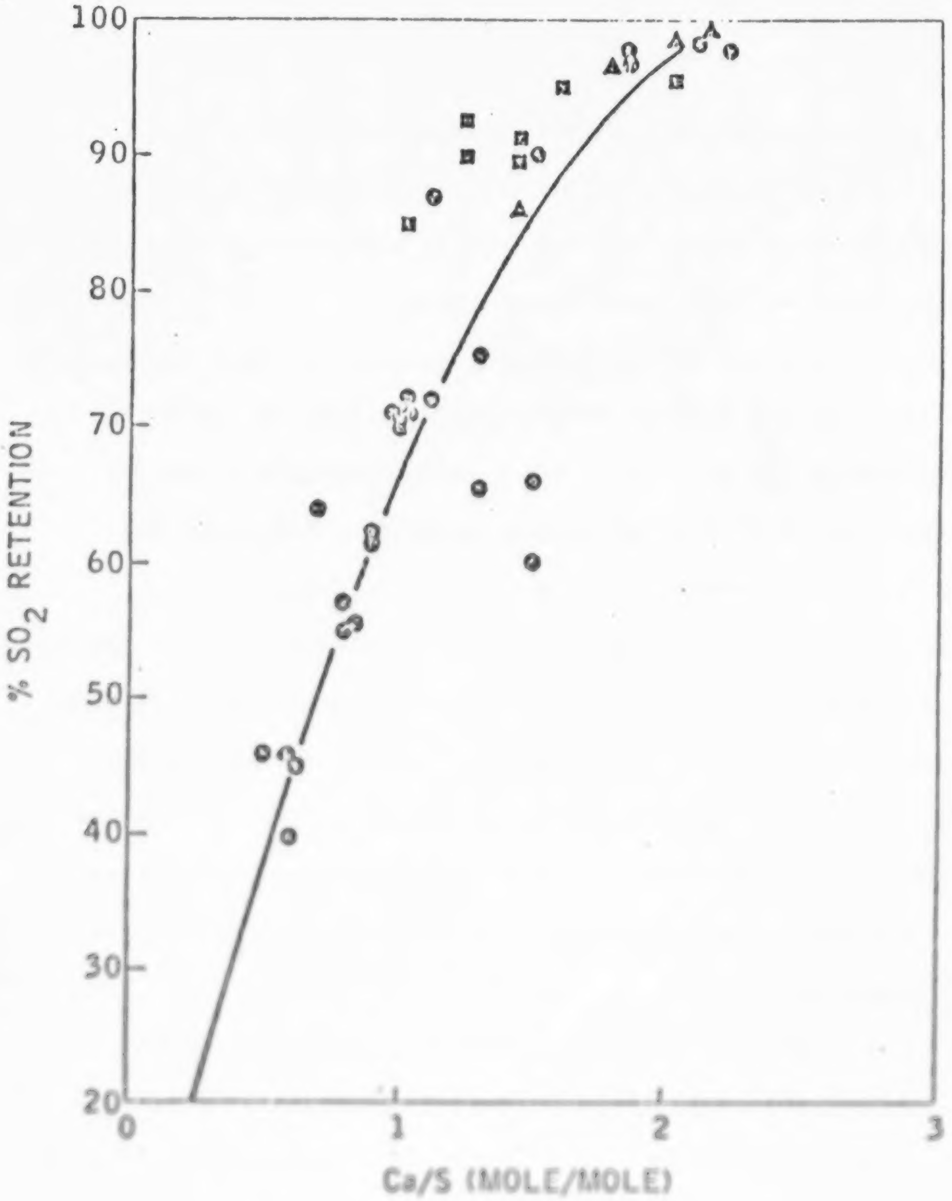

FIGURE 4-14

COMPARISON OF SO_2 REMOVAL RESULTS - DOLOMITE SORBENT requirements. Under present standards, limestone may still be used for sulfur reductions up to 70 percent (~3 percent sulfur coal) since the higher calcium content of limestone compensates for its lower activity. Above this level, the higher activity of dolomite is needed to achieve the necessary sulfur reduction.

Although for some AFBC designs the full scale system may consist of many small modules close in size to those units tested, the PFBC pilot plants are orders of magnitude smaller than proposed commercial units. Efforts in PFBC have concentrated on the use of high sulfur coals, and little if any information is available regarding sulfur removal efficiencies with low sulfur coals (<1 percent S). A 90 percent reduction may be more difficult for low sulfur coals since the rate at which calcium reacts under fluidized bed combustion conditions is first order in SO_2 concentration.

4.3.3 Status of FBC

The atmospheric process is inherently simpler and, thus, more fully developed than the pressurized process. Widespread industrial use of the AFBC is projected for the mid-1980s whereas the PFBC is projected to reach commercialization about 1985. EPA sponsored research indicates, however, that the pressurized process has many advantages over the atmospheric process in terms of reduced number of coal feed points, better pollution control, and higher energy conversion efficiency. Emissions of carbon monoxide, hydrocarbons, SO_x and NO_x are inherently less from PFBC than from an

AFBC. Cost estimates show that for utility-industry applications an AFBC and PFBC boiler plant may provide savings on both capital and annualized costs over the costs of a conventional pulverized coal-fired plant with a stack-gas cleanup system. However, this potential will be affected by the results of the current research program as well as any NSPS revision.

While there are no commercial utility FBC plants operating in the U.S., there are several test facilities operating, under construction, or planned. Table 4-9 lists the number of operating units, some of which were used to develop the data discussed here.

Though no actual reliability data are available based on the simplicity of the FBC concept, good reliability is expected. Major problem areas are expected to be:

- Hot gas clean-up
- Materials of construction
- Current lack of design data for scale-up.

Various development programs are addressing the first two areas, and it is anticipated that information from the 30-MWe AFBC unit Rivesville, West Virginia pilot plant and other systems will resolve the third.

4.3.4 FBC Vendors

Though not yet commercially proven, at least two manufacturers are currently marketing industrialized FBC steam generating systems. While they are making some operating performance guarantees, the

TABLE 4-9

SELECTED LIST OF OPERATIONAL FLUIDIZED BED COMBUSTORS

Unit Name and Location	Size/Capacity	Scale	Type
Pope, Evans, and Robins DOE, Alexandria, Va.	9 sq. ft. 0.5 MWe	PDU[a]	AFBC[b]
Pope, Evans and Robins DOE, Rivesville, W. Va.	4 sq. ft. 3.0 MWe	Pilot Scale	AFBC
Babcock and Wilcox Renfrew, Scotland	6.1 MWe	PDU	AFBC
Argonne National Laboratory, Argonne, Ill.	6" diameter	Bench	PFBC[c]
Exxon EPA, Linden, N.J.	12.5" diameter 0.63 MWe	Miniplant	PFBC
British Coal Utilization Research Association, England	6sq. ft. 0.5 MWe	Bench	PFBC

[a] Process Development Unit

[b] Atmospheric Fluidized Bed Combustion

[c] Pressurized Fluidized Bed Combustion

status of environmental performance guarantees is still somewhat undetermined. A greater number of manufacturers are offering FBC incinerators with waste heat boilers attached. No commercial utility size systems are expected until about 1985.

4.3.5 Summary

Theoretically, FBC can be employed as a control technique to meet reduced emission standards. Whether or not this can be achieved practically and economically depends on the course of the research and development activities.

4.4 Flue Gas Desulfurization

Sulfur compounds can be removed from fossil fuel combustion gases through the application of a large number of specific chemical processes. Many have been evaluated as potential means of treating the flue gases from coal-fired boilers. Some processes have been rejected as impractical, unreliable, or uneconomical, while others are in various phases of development or have been applied commercially.

4.4.1 Overview of Flue Gas Desulfurization Processes

The principal types of flue gas desulfurization processes that have been tested or are currently being tested can be classified in accordance with the scheme illustrated in Figure 4-15. A major distinction is made between throwaway processes, in which all waste streams are discarded, and regenerable processes in which the sorbent is regenerated and recycled. In certain regenerable processes,

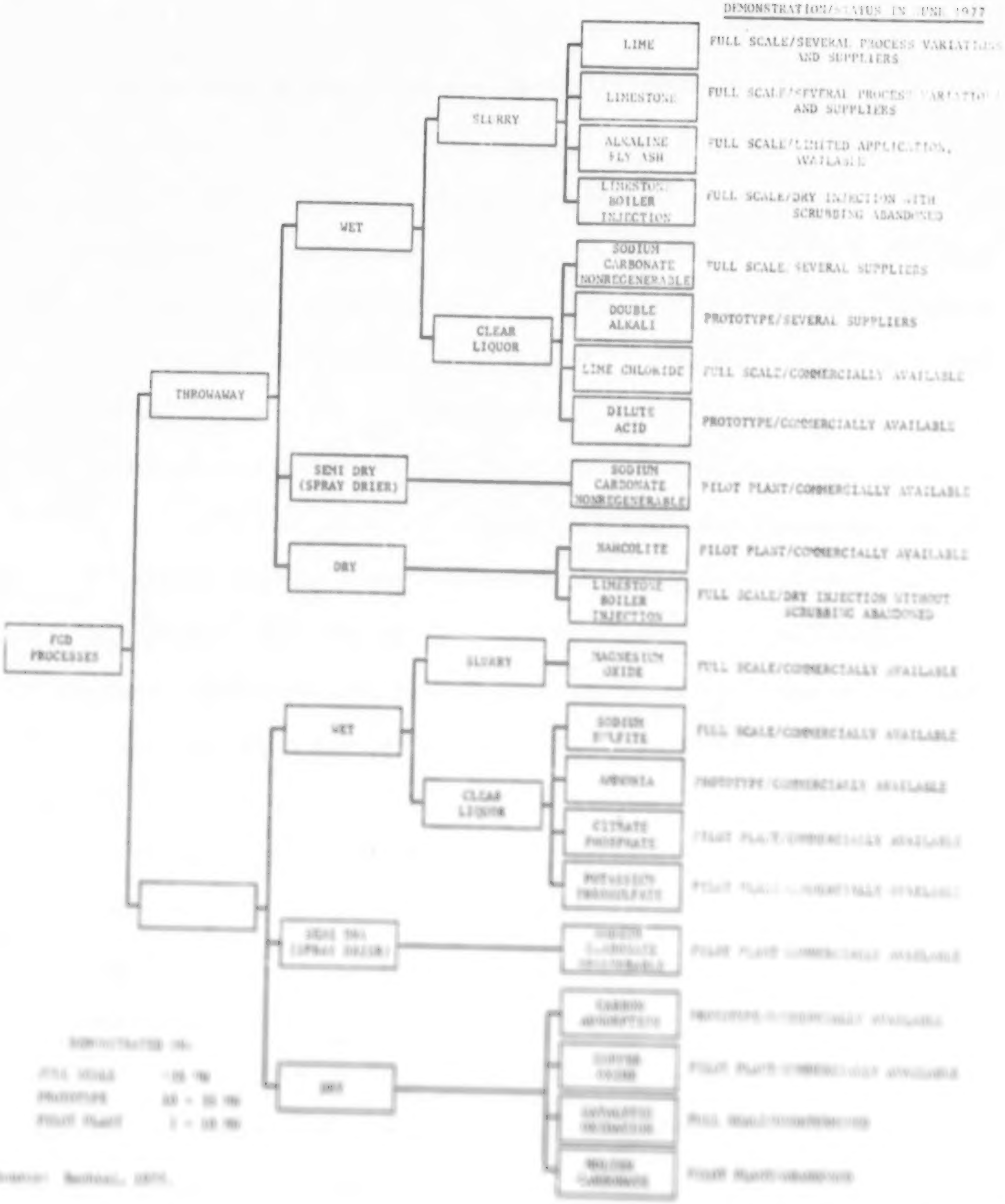
DEMONSTRATION/STATUS IN JUNE 1977
FGD PROCESSES
THROWAWAY
WET
SLURRY
LIME
FULL SCALE/SEVERAL PROCESS VARIATIONS AND SUPPLIERS
LIMESTONE
FULL SCALE/SEVERAL PROCESS VARIATIONS AND SUPPLIERS
ALKALINE FLY ASH
FULL SCALE/LIMITED APPLICATION, AVAILABLE
LIMESTONE BOILER INJECTION
FULL SCALE/DRY INJECTION WITH SCRUBBING ABANDONED
CLEAR LIQUOR
SODIUM CARBONATE NONREGENERABLE
FULL SCALE/SEVERAL SUPPLIERS
DOUBLE ALKALI
PROTOTYPE/SEVERAL SUPPLIERS
LIME CHLORIDE
FULL SCALE/COMMERCIALLY AVAILABLE
DILUTE ACID
PROTOTYPE/COMMERCIALLY AVAILABLE
SEMI DRY (SPRAY DRIER)
SODIUM CARBONATE NONREGENERABLE
PILOT PLANT/COMMERCIALLY AVAILABLE
DRY
NAHCOLITE
PILOT PLANT/COMMERCIALLY AVAILABLE
LIMESTONE BOILER INJECTION
FULL SCALE/DRY INJECTION WITHOUT SCRUBBING ABANDONED
WET
SLURRY
MAGNESIUM OXIDE
FULL SCALE/COMMERCIALLY AVAILABLE
CLEAR LIQUOR
SODIUM SULFITE
FULL SCALE/COMMERCIALLY AVAILABLE
AMMONIA
PROTOTYPE/COMMERCIALLY AVAILABLE
CITRATE PHOSPHATE
PILOT PLANT/COMMERCIALLY AVAILABLE
POTASSIUM THIOSULFATE
PILOT PLANT/COMMERCIALLY AVAILABLE
SEMI DRY (SPRAY DRIER)
SODIUM CARBONATE REGENERABLE
PILOT PLANT/COMMERCIALLY AVAILABLE
DRY
CARBON ADSORPTION
PROTOTYPE/COMMERCIALLY AVAILABLE
COPPER OXIDE
PILOT PLANT/COMMERCIALLY AVAILABLE
CATALYTIC OXIDATION
FULL SCALE/DISCONTINUED
MOLTEN CARBONATE
PILOT PLANT/ABANDONED
DEMONSTRATED ON:
FULL SCALE >100 MW
PROTOTYPE 10 - 50 MW
PILOT PLANT 1 - 10 MW

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FIGURE 4-13

FLUE GAS DESULFURIZATION PROCESSES TESTED ON COAL-FIRED BOILERS elemental sulfur or sulfur compounds can be recovered from waste streams as marketable products.

Flue gases can be treated through wet, semidry or dry desulfurization processes of both throwaway and recovery types. Wet processes are subdivided further into the categories of slurry processes and clear liquor processes. In slurry processes a suspension of active sorbent is used to contact or scrub the gas stream. Examples of slurry processes are lime and limestone scrubbing and the regenerable magnesium oxide (MAGOX) process.

Wet scrubbing processes can remove both fly ash and sulfur dioxide simultaneously from a gas stream. In practice, however, there may be good reasons for collecting fly ash separately, generally by means of electrostatic precipitators or fabric filter (baghouse). Possible interference with the process reactions is avoided by removing the fly ash upstream of the desulfurizing unit, and erosion of the desulfurization process equipment is reduced. The volume of sludge is also minimized when the fly ash is removed prior to the desulfurization process. In addition, contamination of the reagents and by-products is prevented.

Potential problems with scaling, plugging, and erosion can be minimized in clear liquor scrubbing processes. Clear liquor desulfurization processes involve various scrubbing solutions (Figure 6-15), including sodium carbonate (used in the throwaway, single alkali process), sodium sulfite (double alkali process and Wellman-Lord process), and ammonia.

All wet processes cause a considerable cooling of the treated flue gas and an increase in its moisture content. Reheat of the gas prior to discharge may be desirable in certain applications to avoid condensation and corrosion in ducts, fans and stacks downstream of the scrubber and to restore the buoyancy of the flue gas entering the stack. Avoidance of a visible stack plume (due to condensation) may be an added incentive to reheat the gas. These drawbacks are largely circumvented in semidry and dry processes. Further, the disposal of solid wastes generated in semidry and dry throwaway processes may be easier than the disposal of sludges and liquid wastes.

In the semidry process, the flue gas is contacted by small quantities of spray containing sodium carbonate. The spent sorbent may be either discarded or regenerated. Dry, throwaway processes that have been tested on coal-fired boilers entail the use of nahcolite (a mineral containing natural sodium bicarbonate) or limestone (consisting mainly of calcium carbonate) injected into the boiler. The two dry regenerable processes that have been demonstrated on a pilot plant or prototype scale are the carbon absorption and copper oxide processes. In the latter, flue gases are treated at temperatures above 371°C (700°F), a feature that tends to enhance the attractiveness of the system in new rather than retrofit applications. Nahcolite can be injected at temperatures above or below 149°C (300°F), although better sulfur removal efficiency is achieved at higher temperatures. Flue gases are desulfurized by the carbon adsorption process at temperatures that may be lower than 149°C (300°F), making the process amenable to retrofit installations downstream of air heaters in power plants.

Though there is research and development work being done on wet, semidry, and dry processes, the most successful accomplishments to date have been with the wet processes in both the throwaway and regenerable categories. As a result the six most highly developed and applied systems are all wet systems:

Throwaway	Regenerable
Lime scrubbing	Magnesium Oxide
Limestone scrubbing	Sodium Sulfite
Sodium Carbonate	
Dual Alkali	

These processes are expected to make up the largest portion of new scrubber installations in the near future. Therefore, the major portion of this text will address these wet systems.

4.4.2 Sulfur Dioxide Removal

In practice, the effectiveness of a particular wet scrubbing system for removing sulfur dioxide from flue gases is dependent on a number of design features and operating parameters. Principal among these are:

1. Liquid-to-Gas Ratio. Removal of sulfur dioxide from flue gases is generally improved by a high ratio of liquid flow to gas flow since, with a large circulating volume of scrubbing medium, the concentration of dissolved sulfur dioxide is kept low and a large gas-liquid interface area can be provided. An increasing penalty, in terms of the power

expended in circulating the scrubbing medium, is incurred as the liquid-to-gas ratio is increased. Liquid-to-gas ratios, expressed as gallons of liquid pumped through the scrubber per thousand cubic feet of gas flow, are typically of the order of 20 in venturi scrubbers, 50 in turbulent contact absorbers, and 80 in spray towers (Bechtel, 1977).

2. Gas Velocity. Flue gas desulfurization is generally improved if the velocity of the flue gas is kept low and the residence time of the gas in the scrubber is lengthened. For a given throughput of gas, a low velocity can be attained at the expense of larger scrubbing equipment. However, the disadvantage of a high gas velocity can be offset in part, by a high gas-liquid interface area. An upper limit to the gas velocity may then be set in consideration of the quantity of mist that is entrained with the gas. Gas velocities are typically of the order of 5 to 30 feet per second in tower scrubbers and in excess of 100 feet per second in venturi scrubbers (Bechtel, 1977). The gas residence time in the venturi scrubbers may be as low as a few hundredths of a second.

3. Gas Turbulence. A high degree of turbulence in the gas stream is advantageous in promoting the rapid diffusion of sulfur dioxide from the bulk flue gas to the gas-liquid interface.

4. Slurry Holdup. A relatively long holdup residence time of the scrubbing medium in the scrubber is desirable to allow a more complete transfer of sulfur dioxide from the flue gas. In slurry scrubbing with lime or limestone, the holdup time is of particular importance since

the uptake of sulfur dioxide is controlled by the slow dissolution of suspended alkaline material. Residence times of slurries in towers with packing may range up to 5 seconds or more (Bechtel, 1977). At the other extreme, the residence time of slurries in venturi scrubbers may be of the order of a few hundredths of a second per pass, a feature that constrains such systems to somewhat lower removal efficiencies. However, it can be increased by multiple staged scrubbers.

5. Scrubber Internals. The function of the internals or packing in tower-type scrubbers is to provide a high gas-to-liquid interface area. Several types of internals are in common use, including staged moving spheres on grids, closely spaced rods or grills and perforated trays. Fixed packings are generally not used in slurry service because of the tendency to plug or scale. The absorbent is often sprayed into the towers through several stages of spray headers.

6. Flow Configuration. Scrubbers can be designed to operate so that the gas and scrubbing medium flow is countercurrent, crosscurrent, or concurrent. Countercurrent and crosscurrent flows have an inherent advantage in that the cleanest gas comes in contact with the freshest absorbent, but comparable performance can be attained in concurrent flow with multiple stages of spray.

In addition to the parameters that govern the desulfurization performance of a particular device, other characteristics of the system are important in determining the operating costs associated with the system and its ability to function under the variations in load during normal operation. One major factor that determines the energy costs associated with a scrubber system is the pressure drop in the gas across the scrubber and the system. Additional factors include thermal energy for the reheat system and the pumping power required for the circulation of the scrubbing medium. Energy requirements for the FGD systems and the impact on steam/electric generation are discussed in Appendix B.

Varying loads on a boiler are accompanied by variations in the flow rate of the flue gases, and scrubbers are required to maintain satisfactory levels of performance under partial load conditions. Some scrubbers are designed to be "turned down" to 50 percent of design load, while others are constructed of individual sections that can be isolated and closed off. A venturi can have a variable throat area to accommodate turndown. In big installations with more than one scrubber, individual modules can be taken out of service as the load is reduced.

4.4.2.1 Scrubbing Equipment. Scrubbing equipment that is in general use with wet desulfurization processes falls generally into the broad categories of packed towers, spray towers, tray columns, and venturi scrubbers.

A packed scrubber is a device consisting of a tower filled with one of many available packing materials between pairs of support and restraining grids. Conventional packing materials such as raschig rings, berl saddles, intalox saddles, and ball rings are of little use in slurry scrubbing because of their propensity for plugging. With clear liquor scrubbing, high absorption efficiencies can be achieved in conventional packed towers operating with liquid-to-gas ratios of 15 to 30 gallons per thousand cubic feet (Bechtel, 1977).

The turbulent contact absorber (TCA) is a countercurrent multistage scrubber consisting of retaining for grids that both support and restrain mobile packing spheres. Good gas-liquid contact and scale removal result from the turbulent movement of the spheres. Two to four stages may be used and high sulfur dioxide removal can be attained in slurry scrubbing at liquid-to-gas ratios of 40 to 60 gallons per ACFM of gas flow (Bechtel, 1977). The pressure drop per stage is approximately 2 to 2.5 inches of water (Bechtel, 1977). A schematic of the turbulent contact absorber is shown in Figure 4-16.

In a marble bed absorber, a fixed bed of glass spheres (marbles), typically 4 inches in diameter, is kept in slight vibrating motion and creates a turbulent layer of liquid and gas above the spheres. Pressure drops across marble bed scrubbers are generally between 4 and 6 inches of water and the operating liquid-to-gas ratio is in the range of 25 to 30 gallons per thousand cubic feet (Bechtel, 1977).

A spray tower is a countercurrent type of scrubber in which the absorbent is sprayed through several headers and nozzles. Spray towers can be designed to operate with a relatively low pressure

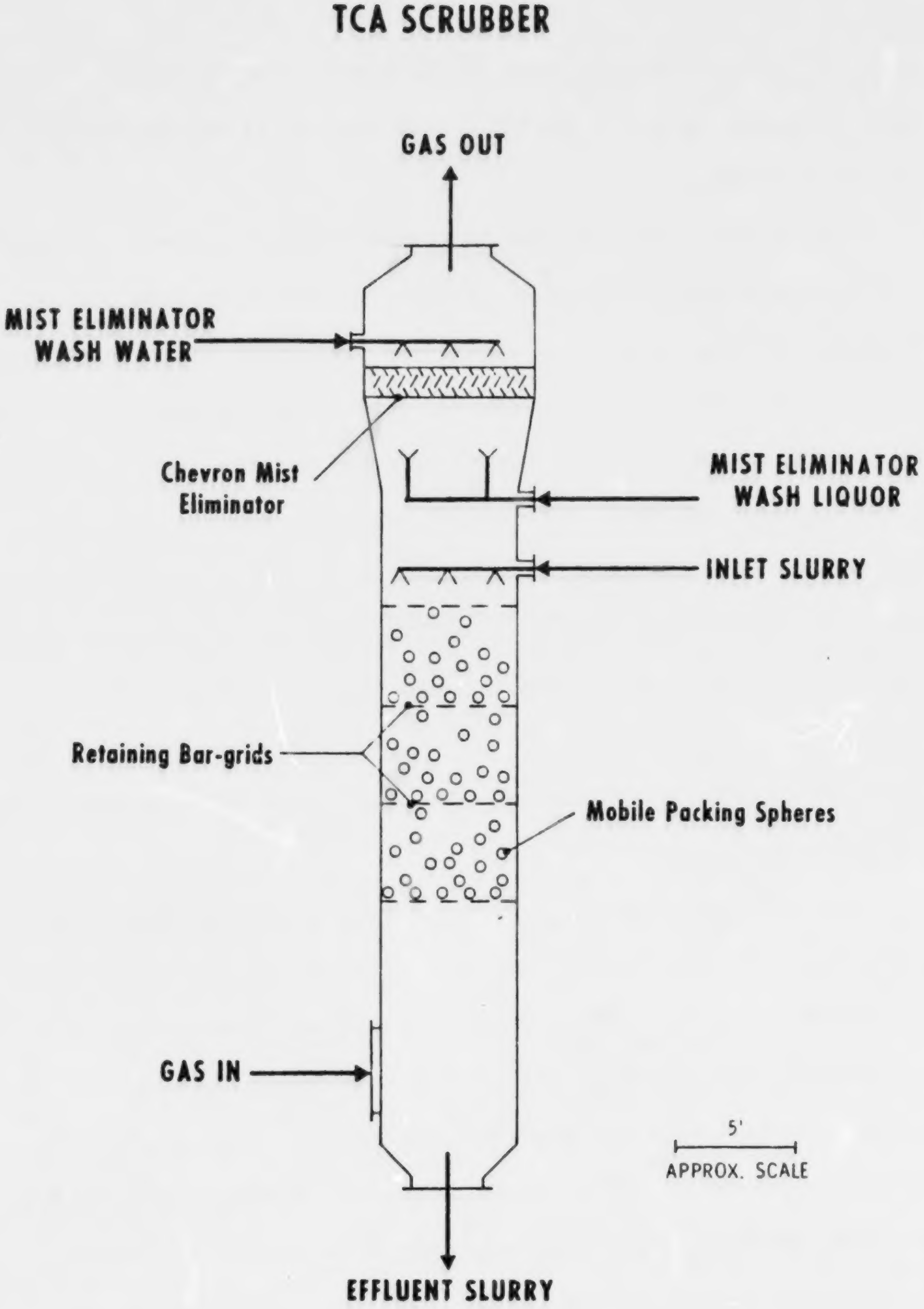

TCA SCRUBBER
GAS OUT
MIST ELIMINATOR WASH WATER
Chevron Mist Eliminator
MIST ELIMINATOR WASH LIQUOR
INLET SLURRY
Retaining Bar-grids
Mobile Packing Spheres
GAS IN
5'
APPROX. SCALE
EFFLUENT SLURRY

FIGURE 4-16

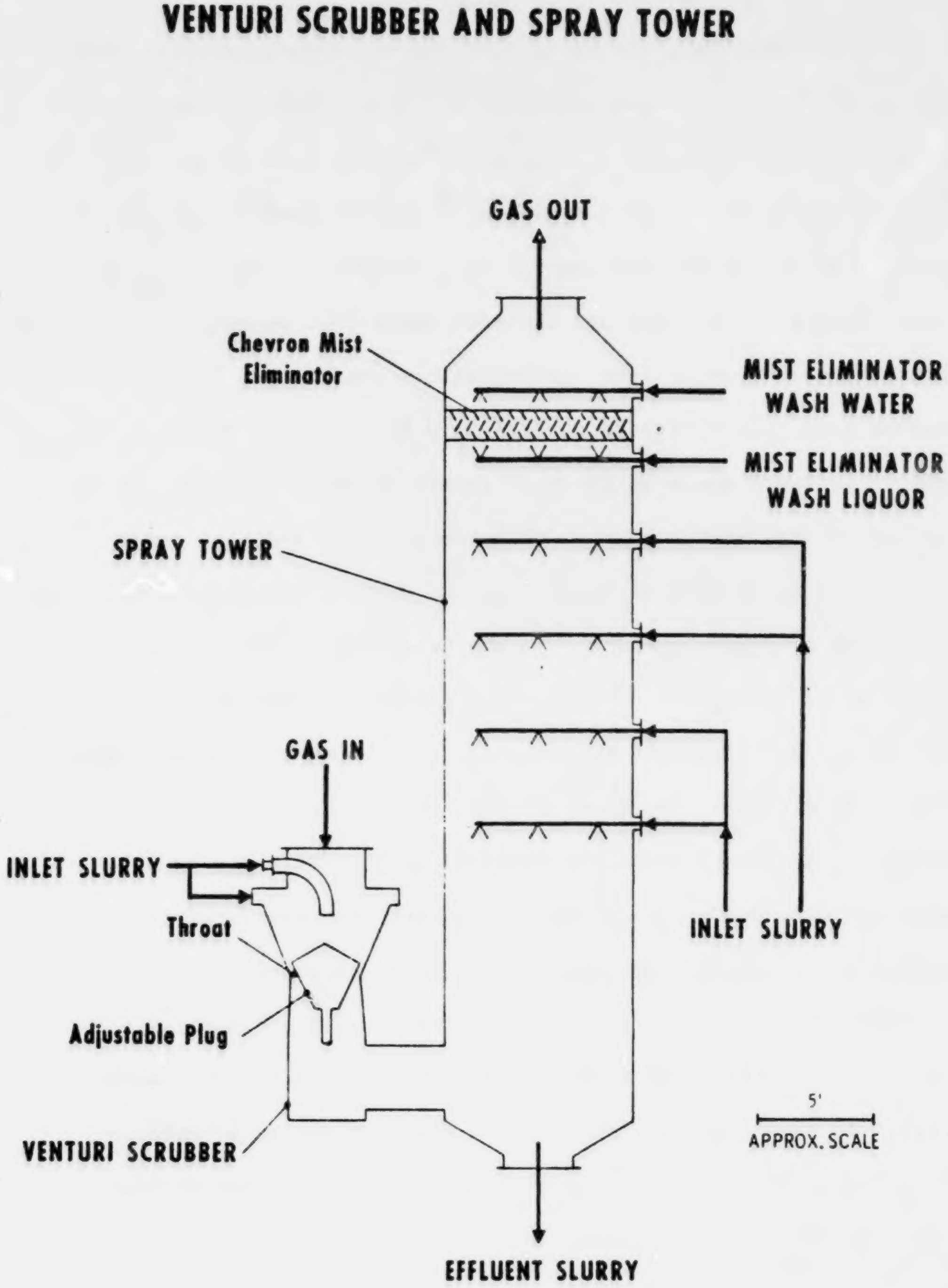
SCHEMATIC OF THREE-BED TCA

drop, but liquid-to-gas ratios of the order of 80 gallons per thousand cubic feet are needed to attain a high removal of sulfur dioxide from the gas streams.

Tray columns are designed to provide contact between gas and liquid in a series of trays or plates. At each tray, the gas is dispersed through a layer of liquid and the number of trays (stages) required in a particular application depends on the ease with which the mass transfer operation can be effected and the overall degree of SO_2 removal required. The liquid residence time in the column is long, and a high degree of sulfur dioxide removal can be achieved with a relatively low pressure drop (Bechtel, 1977). A liquid-to-gas ratio of 40 gallons per thousand cubic feet is typical in tray columns (Bechtel, 1977). Scaling presents a potential problem in this type of device and undersprays at the trays are required to wash off soft scale.

Several other types of scrubber towers or columns have been applied to flue gas desulfurization, including the cross-flow absorber and screen, or grid, tower. Cross-flow absorbers are installed horizontally and have been tested both with packing and sprays. Pressure drops across the absorbers are low, but high liquid-to-gas ratios are needed to effect a high degree of sulfur dioxide removal (Bechtel, 1977). Screen scrubbers consist of stacks of five to ten screens, typically with 7/8 inch openings. Pressure drops in screen scrubbers are low and liquid-to-gas ratios generally exceed 50 gallons per thousand cubic feet (Bechtel, 1977).

Venturi scrubbers are being used for the removal of both particulate matter and sulfur dioxide from flue gas streams. These devices generate a high degree of liquid-gas mixing and contact but have the disadvantages of a relatively short contact time and a high pressure drop. In fly ash removal applications, a liquid-to-gas ratio of 10 to 30 gallons per thousand cubic feet produces a reduction in particulate loading from typical values encountered in coal-fired boilers down to 0.02 grains per standard cubic feet. The associated drop in pressure would be 10 to 15 inches of water (Bechtel, 1977). Because of the short contact time between liquid and gas, removal of sulfur dioxide with a single stage of venturi scrubbing is limited. Using lime or limestone slurry as the scrubbing medium, approximately 40 to 50 percent of the sulfur dioxide present in a flue gas stream can be removed by a single-stage venturi scrubber (Bechtel, 1977). To attain higher removal efficiencies, two or more stages of venturi scrubbers would be required. Alternatively, magnesium oxide can be added to the slurry to improve its desulfurization properties or an after absorber can be added downstream of the scrubber. This latter arrangement is illustrated schematically in Figure 4-17, which shows a venturi scrubber combined with a spray tower. In this instance, the venturi scrubber has an adjustable throat area, a feature that permits operation of the device over a wide range of flow conditions.


VENTURI SCRUBBER AND SPRAY TOWER
GAS OUT
Chevron Mist Eliminator
MIST ELIMINATOR WASH WATER
MIST ELIMINATOR WASH LIQUOR
SPRAY TOWER
GAS IN
INLET SLURRY
Throat
Adjustable Plug
INLET SLURRY
VENTURI SCRUBBER
5'
APPROX. SCALE
EFFLUENT SLURRY

Source: Bechtel, 1977.

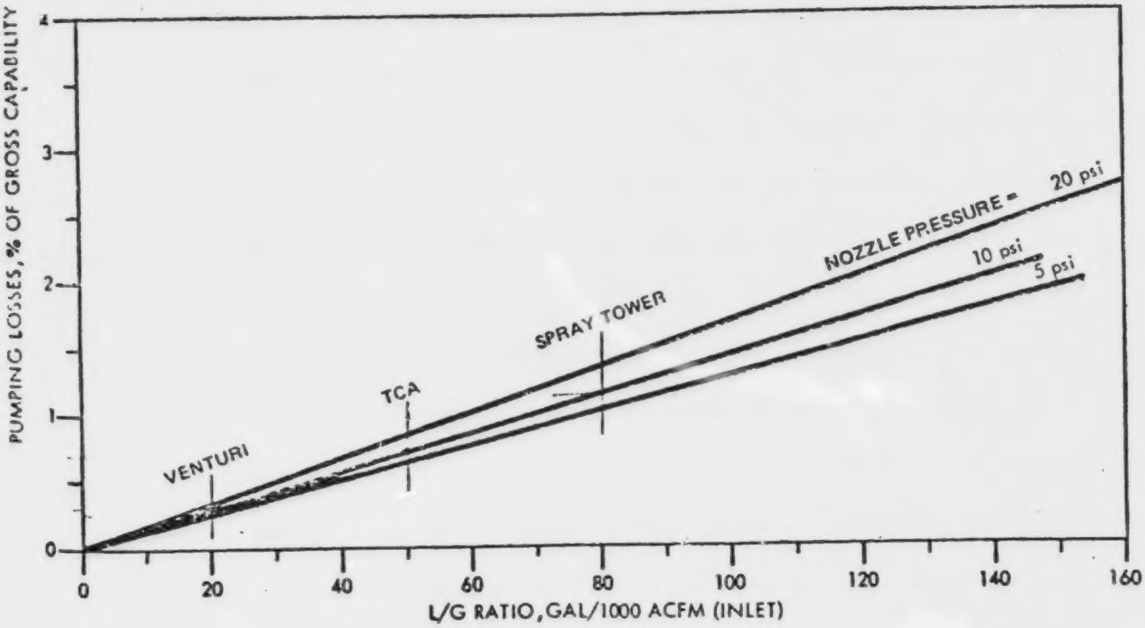
FIGURE 4-17

SCHEMATIC OF VENTURI SCRUBBER AND SPRAY TOWER

4.4.2.2 Energy Requirements. The major energy requirements of the wet flue gas desulfurization processes are those associated with the circulation of the liquid absorbing medium and the compensation for the (gas) pressure drop across the device. In addition, a further expenditure of energy is incurred if the flue gas is reheated to reduce corrosion in the stack, to restore plume buoyancy, or to prevent the formation of a visible plume at the stack exit. Appendix C briefly describes reheat systems and their operations.

Typical relationships between the energy lost in circulating the scrubbing medium and liquid-to-gas ratio are illustrated in Figure 4-18. Energy losses are expressed in terms of the fraction of a power plant's gross electrical output that is expended in operation of pumps, fans, small auxiliaries, additional process equipment and thermal energy for exhaust gas reheat. These losses increase both with increasing liquid-to-gas ratio and with the pressure at which the scrubbing absorbing medium is injected into the scrubber. During conditions representing the operation of venturi scrubbers, pumping losses amount to approximately 0.25 percent of gross station capability. Greater pumping losses are incurred with turbulent contact absorbers (0.75 percent) and spray towers (1 percent).

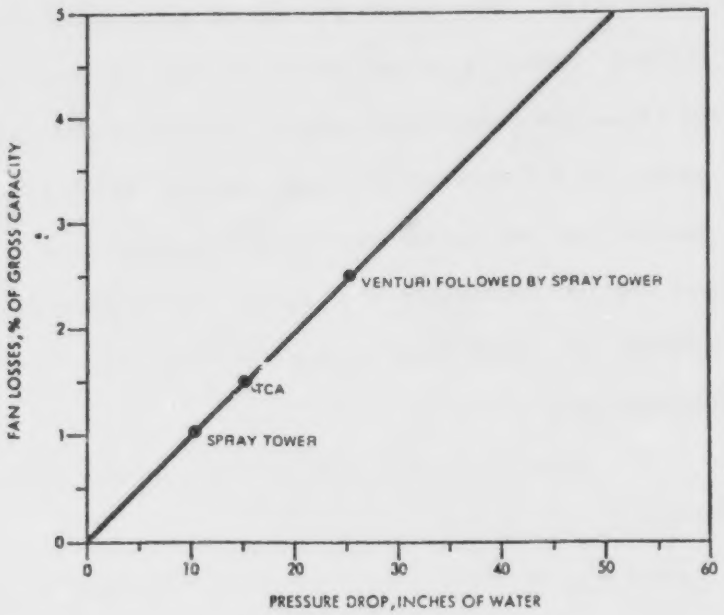
Fans are used to compensate for the drop in pressure across a scrubbing device and to maintain an appropriate flow of flue gases through the combustion system. The energy utilization in fans increases with increasing pressure drop, as indicated in Figure 4-19. Spray towers typically give rise to the smallest pressure drops



Source: Bechtel, 1977.

FIGURE 4-18

STATION ELECTRICAL LOSS AS A FUNCTION
L/G RATIO AND NOZZLE PRESSURE



Source: Bechtel, 1977

FIGURE 4-19

STATION ELECTRICAL LOSS AS A FUNCTION
OF DRAFT REQUIREMENTS

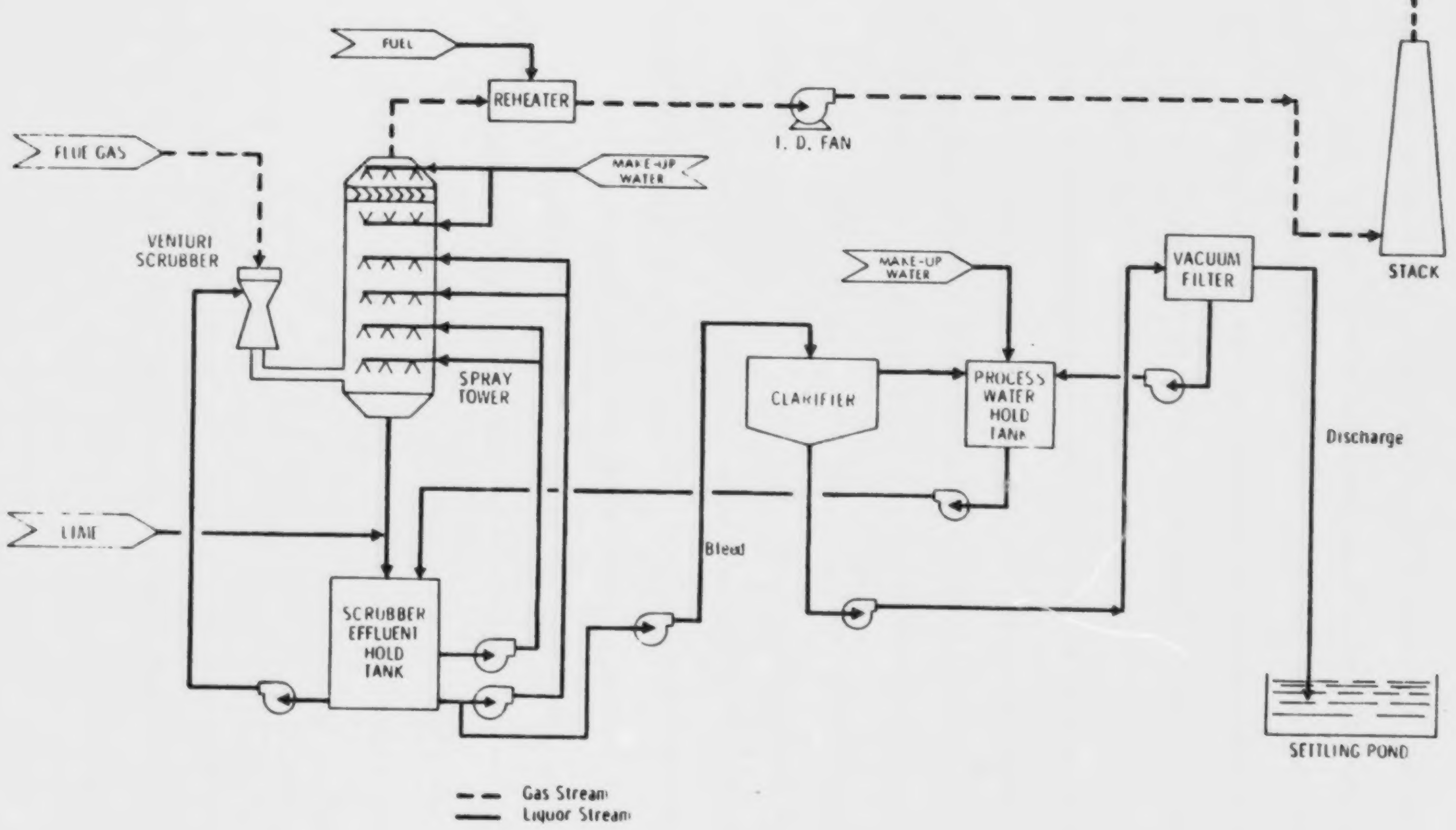
and their operation involves a loss of approximately 1 percent of gross station capability. Fan losses associated with the operation of turbulent contact absorbers amount to 1.5 percent of gross station capability, and those associated with venturi scrubbers followed by spray towers amount to 2.5 percent of gross station capability. The aggregate of pumping and fan losses then ranges roughly from 2 percent of gross station capability with spray tower equipment to 4 percent with venturi and spray tower combinations.

4.4.3 FGD Processes

The process descriptions in this section are limited to those that are commercially successful.

4.4.3.1 Lime/Limestone Processes. Lime and limestone scrubbing operations are similar; both employ a slurry containing suspended alkali as the SO_2 absorbent medium. The basic difference is that the lime process utilizes a lime-slaking process to produce a lime ($Ca(OH_2)$) slurry for scrubbing the flue gas, and the limestone process utilizes finely ground limestone in its slurry. A typical flow diagram for the lime/limestone processes is presented in Figure 4-20.

The flue gas from the boiler enters the scrubber where it is scrubbed by the respective slurry. The scrubbed gas then passes through the mist eliminator which removes any entrained mists or particulate matter in the gas. The cleaned flue gas is reheated to increase buoyancy and prevent condensation of the moisture in the gas.


FUEL
REHEATER
I. D. FAN
STACK
FLUE GAS
MAKE-UP WATER
VENTURI SCRUBBER
SPRAY TOWER
MAKE-UP WATER
VACUUM FILTER
CLARIFIER
PROCESS WATER HOLD TANK
Discharge
LIME
Bleed
SCRUBBER EFFLUENT HOLD TANK
SETTLING POND
Gas Stream
Liquor Stream

Source: Bechtel, 1977.

FIGURE 4-20

TYPICAL PROCESS FLOW DIAGRAM
FOR LIME/LIMESTONE SCRUBBING

The absorbed SO_2 reacts with dissolved alkali and results in a calcium sulfite and calcium sulfate precipitate that make up the major portion of the waste products. The slurry from the scrubbers drains to holding tanks where the reaction reaches or approaches completion. Makeup lime or limestone is added to the slurry in the tank and reusable slurry is recycled to the scrubbers. This recycled slurry contains from 5 to 15 percent suspended solids including fresh alkali, reacted waste products, and fly ash. To remove the solid waste products, a portion of the recycled material is withdrawn to the solids separation equipment. A clarifier (thickener or settling tank) separates the suspended solids and clear liquid. The liquid is then returned to the scrubber loop. The waste product stream for the clarifier containing 20 to 40 percent solids is directed through a filter to further reduce volume and increase the solids concentration to greater than 60 percent. These wastes are then discharged to a disposal pond area. The clarifier and/or filter are optional; however, elimination of these steps results in a greater volume of sludge sent to the disposal area. In this case, once settling occurs, the clear liquid may be removed from the top of the ponding area and returned to the system.

Makeup water is added to the slurry to replace evaporated water and water entrained in the waste stream. The water is added as mist eliminator wash water through pump seals and the lime slaker (for the lime process only).

A summary evaluation of the lime and limestone process is presented in Table 4-10. These systems are the most popular because of their proven operation and lower cost. A discussion of factors affecting removal efficiency appears in Appendix D. The appendix also includes detailed discussions of the mist eliminator and chemical scaling problems and techniques employed to reduce or eliminate the problems.

The lime and limestone systems make up the largest portion (greater than 90 percent) of operating scrubbers (PEDCo, 1977). While early lime or limestone scrubbers had some operational problems, the operability and reliability of the newer systems has been very good.

In 1972 the Phillips Power Station of Duquesne Light Company began operation as the first major domestic lime FGD system. Since that time, 11 other major stations have installed lime scrubbers (Table 4-11). Each of the systems that has been tested is operating at or above the SO_2 efficiency required to meet SO_2 emission legislation.

Three lime units, Green River, Bruce Mansfield, and Mohave, are briefly discussed here since they are examples of the availability and/or SO_2 removal efficiencies of lime systems for both high and low sulfur coal applications. The Mohave unit is a demonstration unit and is not representative of availability data. It is discussed because of its SO_2 removal efficiency.

TABLE 4-10

LIME/LIMESTONE PROCESS EVALUATION

PARAMETERS	COMMENTS
Process complexity, operability, and reliability	Relative simplicity and lower costs make systems currently most popular. Some problems with scaling, plugging, erosion and corrosion.
Process performance	Capability of greater than 90 percent SO_2 removal has been shown.
Wastes/product	Systems produce large quantities of waste sludge.
Development status	Commercially available for full scale commercial operation on coal-fired boilers.
Advantages/disadvantages	Process can tolerate fly ash; requires high liquid to gas ratios and/or substantial gas pressure drop.

TABLE 4-11

LIME BASED FGD SYSTEMS IN THE UNITED STATES

Station	Company	Size, (MW)	Start-up date	Status	New or retrofit	Coal, % sulfur	Design SO_2 removal efficiency, %
Bruce Mansfield	Pennsylvania Power Co.	835	April 1976	Operational	N	4.7	92
Cane Run	Louisville Gas & Electric	178	August 1976	Operational	N	3.5-4	85
Colstrip	Montana Power Co.	360	December 1975	Operational	N	0.8	60
Conesville	Columbus & Southern Ohio Electric Co.	400	February 1977	Operational	N	4.5-4.9	90
Elrama	Duquesne Light Co.	510	October 1975	Operational	R	1-2.8	85
Four Corners	Arizona Public Service	160	February 1976	Test facility shutdown	R	0.7	N.A.
Green River	Kentucky Utilities	64	September 1975	Operational	R	3.8-4	80
Mohave	So. California Edison	160	November 1973	Test facility shutdown	R	0.8	N.A.
Paddy's Run	Louisville Gas & Electric	65	April 1973	Operational	R	3.5-4	80
Phillips	Duquesne Light Co.	410	April 1972	Operational	R	1-2.8	83
Rickenbacker	USAF	20	March 1976	Operational	R	3.6	90
Shawnee	TVA/EPA	10	April 1972	Test facility	R	2.9	N.A.

Source: PEDCo., 1977d.

The lime slurry unit at the Green River Station of Kentucky Utilities is attached to boilers 1, 2, and 3 which supply steam for two turbines with a total capacity of 64 MW. These generating units are peaking units and normally operate 5 days per week, with one or more of the boilers at reduced capacity. The boilers use high sulfur coal with about 25,100 KJ/Kg (10,800 Btu/lb) heat content (Table 4-12).

Commercial operation of the system started in the fall of 1975. After shakedown tests and discovery and correction of minor problems, the closed loop full capacity operations began in March 1976. To date system performance has been good. Mechanical reliabilty has been excellent as shown by the average system availability, operability reliability, and utilization data in Table 4-13. The operability is plotted through May 1977 in Figure 4-21. The SO_2 removal efficiency has been about 90 percent, well above the 80 percent design value (PEDCo, 1977).

The Bruce Mansfield facility is the largest scrubber in the world and is attached to the 835-MW Bruce Mansfield No. 1 steam generator. The system burns 4.7 percent sulfur coal and must maintain 260 ng/J (0.6 lb $SO_2/10^6$ Btu) or an equivalent greater than 90 percent SO_2 control. Table 4-14 shows design related information.

This facility reported 100 percent operability (hours FGD operated/per hours boiler operated) during the first months after startup from May to December 1976. During the exceptionally cold

TABLE 4-12

POWER PLANT AND FGD SYSTEM DESIGN DATA

Green River - Kentucky Utilities

Boiler data	Generating capacity, MW	64
	Year placed in service	1949
	Boiler manufacturer	Babcock & Wilcox
Coal data	Heat value	25,100 kJ/kg (10,797 Btu/lb.)
	Ash content	13 to 14 percent
	Sulfur content	3.8 percent
FGD system data	SO_2 removal efficiency	80 percent design
	Particulate removal efficiency	99.7 percent
	Startup date	9/75
	Flue gas rate	170 m^3/s (360,000 acfm)
	Flue gas temperature	149°C (300°F)
	Stack height	24 m (78 ft.)
	FGD vendor	American Air Filter

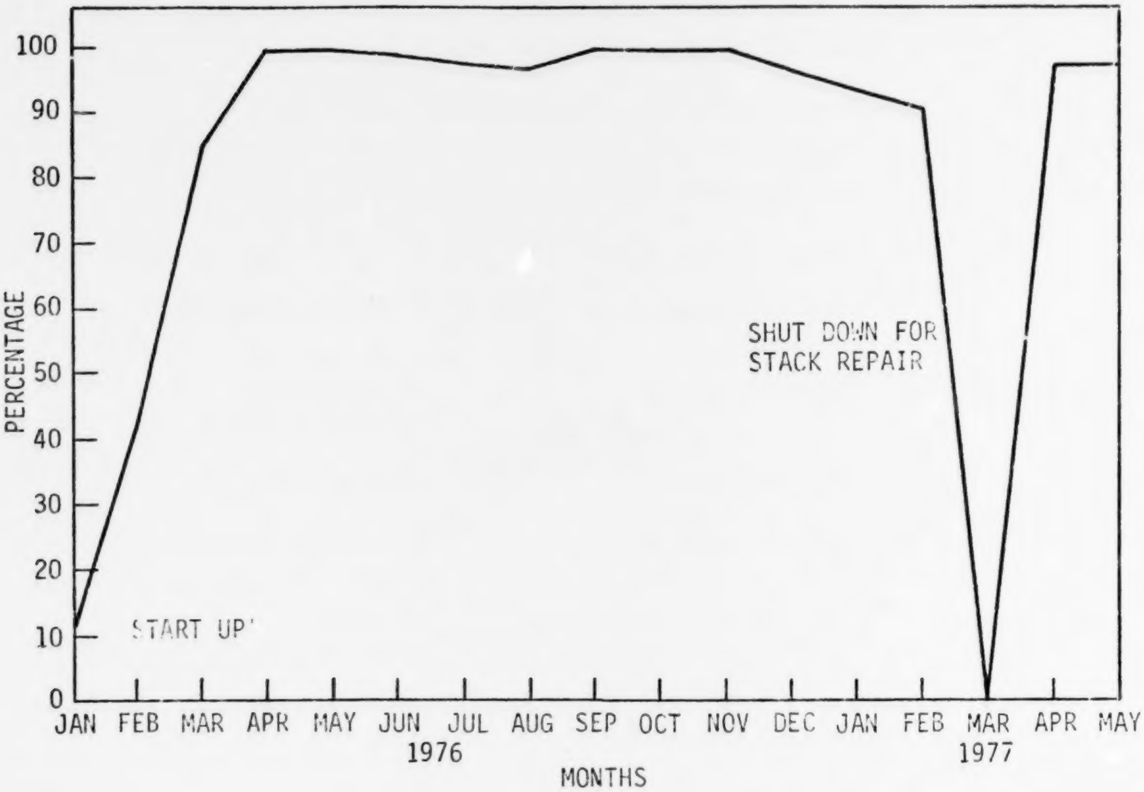
Source: PEDCo, 1977.

TABLE 4-13

GREEN RIVER POWER STATION OPERATIONAL DATA FGD UNIT[25]

Month	1976								
	A Hours in period	B Hours FGD system available	C Hours FGD called upon	D Hours FGD system operated	E Hours boilers operated	B/A % avail-ability	D/C % respond-ability	D/E % oper-ability	D/A % utiliza-tion
January	744	312.00	456.00	64.00	571.55	41.9	14.0	11.2	8.6
February	696	486.17	499.38	210.75	499.38	69.9	42.2	42.2	30.3
March	744	721.72	408.66	386.38	457.53	97.0	94.5	84.4	51.9
April	720	648.00	552.00	552.00	552.00	90.0	100.0	100.0	76.7
May	744	606.18	455.88	455.88	455.88	81.4	100.0	100.0	61.2
June	720	720.00	596.43	588.85	596.43	100.0	98.7	98.7	81.8
July	744	665.85	583.53	574.43	583.53	89.5	98.4	98.4	77.2
August	744	722.45	744.00	722.45	744.00	97.1	97.1	97.1	97.1
September	720	617.20	571.20	571.20	571.20	85.7	100.0	100.0	79.3
October	744	744.00	698.55	698.55	698.55	100.0	100.0	100.0	93.9
November	720	720.00	704.25	704.25	704.25	100.0	100.0	100.0	97.8
December	744	539.31	591.48	517.20	535.52	72.5	87.4	96.6	69.5
Year	8784	7502.88	6861.36	6045.94	6969.82	85.4	88.1	86.7	68.8

SOURCE: PEDCo, 1977



Source: PEDCo, 1977.

FIGURE 4-21

SCRUBBER SYSTEM OPERABILITY - GREEN RIVER NO. 1, 2 AND 3

TABLE 4-14

POWER PLANT AND FGD SYSTEM DESIGN DATA

Bruce Mansfield No. 1 - Pennsylvania Power Co.

Boiler data	Generating capacity	839 MW
	Year placed in service	1976
	Boiler manufacturer	Foster-Wheeler Corp.
Coal data	Heat value	27,700 kJ/kg (11,900 Btu/lb.)
	Ash content	12.5 percent
	Sulfur content	4.5 to 5.0 percent
FGD system	SO_2 removal efficiency	92 percent
	Particulate removal efficiency	99.8 percent
	Start-up date	4/76
	Flue gas rate	1580 m^3/s (3,350,000 acfm)
	Flue gas temperature	196°C (385°F)
	Stack height	290 m (950 ft.)
	FGD vendor	Chemico

Source: PEDCo, 1977.

winter months of January and February 1977, the boiler lost 11 and 24 percent of generation capability as a result of FGD problems. In March the system was taken out of service for a 10-week turbine overhaul. During this time, repairs also began on the chimney flue for A, B, and C modules. The polyester flakeglass lining had failed and was being replaced. The other chimney flue for the D, E, and F modules also needs repair. Roughly 1 year will be required to complete the work and the boiler is being held to half load for that time. Only three FGD modules are required for operation at half load while the repairs are in progress. The D, E, and F modules continued performing and had very good operability during the repair period.

The Mohave generating station is a demonstration facility which has been used for extensive scrubber configuration tests with a scrubber module capacity of approximately 170 MW. The unit employs low sulfur coal (about 0.4 percent). Table 4-15 gives design parameters for the unit. Sulfur dioxide removal efficiency as excellent for all types of absorbers tested. Although the SO_2 inlet concentration was 200 ppm, all of the absorbers were capable of removing 95 percent of the inlet SO_2. Outlet SO_2 loadings ranged from 1 to 10 ppm.

The SO_2 removal efficiency was strongly dependent on L/G for all three modules shown in Figure 4-22. Note that the L/G shown for the horizontal module represents the ratio in each stage. Table 4-16 shows the performance history of the Mohave system. Since this was a test facility, several design changes were made during the period and

TABLE 4-15

POWER PLANT AND FGD SYSTEM DESIGN DATA

Mohave Test Plant - Southern California Edison

Boiler data	Generating capacity	790 MW
	Year placed in service	1971
	Boiler manufacturer	Combustion Engineering
Coal Data	Heat value	26,800 kJ/kg (11,500 Btu/lb.)
	Ash content	10 percent
	Sulfur content	0.4 percent
FGD system data	SO_2 removal efficiency	95 percent
	Particulate removal efficiency	93 percent
	Startup date	11/73
	Flue gas rate	212 m^3/s (450,000 scfm)
	Flue gas temperature	149°C (300°F)
	Stack height	152 m (500 ft.)
	FGD vendor	Southern California Edison Stearns Roger

Source: PEDCo, 1977.

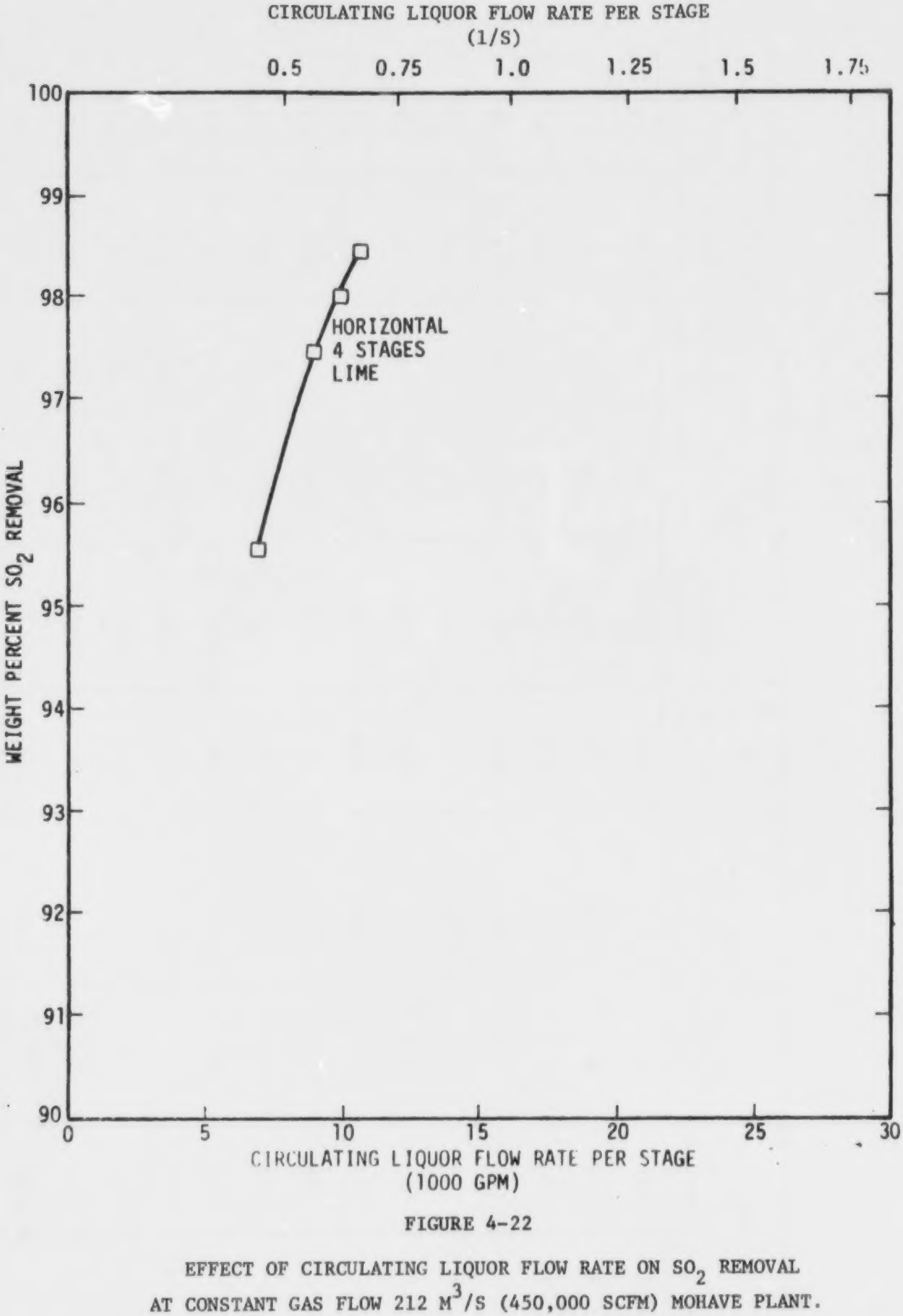


FIGURE 4-22

EFFECT OF CIRCULATING LIQUOR FLOW RATE ON SO_2 REMOVAL AT CONSTANT GAS FLOW 212 M^3/S (450,000 SCFM) MOHAVE PLANT.

TABLE 4-16

OPERATIONAL DATA - MOHAVE HORIZONTAL FGD UNIT

JANUARY 16, 1974 TO FEBRUARY 9, 1975

Months	Hours in period	Avail-able	FGD hours called upon	Opera-ting	Boiler hours	Parameter			
						1 Avail-ability	2 Relia-bility	3 Opera-ability	4 Utiliza-tion
1/74	360	319	358	317	358	89	89	89	88
2/74	672	402	481	393	481	60	82	82	58
3/74	744	592	590	501	682	80	85	73	67
4/74	720	716	563	559	616	99	99	91	78
5/74	744	695	620	571	704	93	92	81	77
6/74	720	552	695	552	695	77	79	79	77
7/74	744	468	596	468	596	63	79	79	63
8/74	744	744	615	615	615	100	100	100	83
9/74	720	720	575	375	647	100	100	58	52
10/74	744	506	540	398	540	68	74	74	53
11/74	720	333	624	249	708	46	40	35	35
12/74	744	739	303	298	572	99	98	52	40
1/74	744	688	591	515	636	90	87	81	69
2/74	208	116	208	116	208	56	56	56	56

Source: PEDCo, 1977.

this work contributed to the unavailability. As a result, operability data for the Mohave unit are not characteristic of a lime system. It should be emphasized that the problems with the horizontal mist eliminator gas flow distribution were solved and are not a problem to future modules of this type.

A list of domestic limestone scrubbing units appears in Table 4-17. Design specifications for the units usually call for 60 to 80 percent SO_2 removal efficiency, depending on local regulations, and all the units that have undergone performance testing have met or exceeded design specifications. Three units that demonstrate the excellent availability that can be achieved by these systems are La Cygne No. 1 and Sherburne No. 1 and No. 2.

The Kansas City Power and Light La Cygne Power Station Unit No. 1 steam generator is a 820-MW (net) system and has one of the earliest limestone scrubber systems installed in the U.S. (1973). The sulfur content of the coal ranges from 5 to 6 percent. System design data are shown in Table 4-18.

The La Cygne FGD was plagued with numerous startup problems, many of which were not due to FGD operation. However, despite the problems at startup, the availability of the system improved steadily. This system is now one of the most reliable large domestic utility FGD systems. Figure 4-23 summarizes availability data. As shown, availability for 1976 averaged 91 percent; the first half of 1977 averaged about 93 percent. This system was designed for 76 percent

TABLE 4-17

MAJOR DOMESTIC FGD INSTALLATIONS - LIMESTONE SLURRY

Station/Unit Power company	Size (MW)	Start-up date	New or retrofit	Coal percentage sulfur	Design SO_2 removal efficiency
Cholla No. 1 Arizona Public Service	115	10/73	Retrofit	0.4-1	58.5 overall 92 in the absorber
Duck Creek No. 1A Central Illinois Light	400	8/78 *	New	2.5-3	75
La Cygne No. 1 Kansas City Power & Light	820	2/73	New	5.0	76
Lawrence No. 4 Kansas Power & Light	125	12/68	Retrofit	0.5	76
Lawrence No. 5 Kansas Power & Light	400	11/71	New	0.5	65
Martin Lake No. 1 Texas Utilities	793	10/77	New	1.0	60
Sherburne No. 1 Northern States Power Co.	710	3/76	New	0.8	50
Sherburne No. 2 Northern States Power Co.	680	9/77	New	0.8	50
Southwest No. 1 Springfield City Utilities	200	4/77	New	3.5	80
Widows Creek No. 8 Tennessee Valley Authority	550	5/77	Retrofit	3.7	80
Will County No. 1 Commonwealth Edison	167	2/72	Retrofit	4.0	82
Winyah No. 2 South Carolina Public Service	280	7/77	New	1.0	70

* One module operated from September 1976 to April 1977.

Source: PEDCo, 1977.

TABLE 4-18

POWER PLANT AND FGD SYSTEM DESIGN/
OPERATING DATA, LA CYGNE NO. 1

Maximum generating capacity	820 MW (net)
Boiler manufacturer	B & W
Year placed in service	1973
Maximum coal consumption	366 metric ton/hr. (404 ton/hr.)
Maximum heat input	8,105 10^6 kJ/hr. (7,676 10^6 Btu/hr.)
Unit heat rate	9880 kJ/kWh (9,360 Btu/kWh)
Stack height above grade	213 m (700 ft.)
Flue gas rate--maximum	1,297 m^3/s (2,760,000 acfm)
Flue gas temperature	141°C (285°F)
Particulate Removal efficiency (actual)	97 to 99 percent
SO_2 Removal efficiency (actual)	70 to 83 percent
No. of FGD modules	8
Process vendor	B & W

Source: PEDCo, 1977.

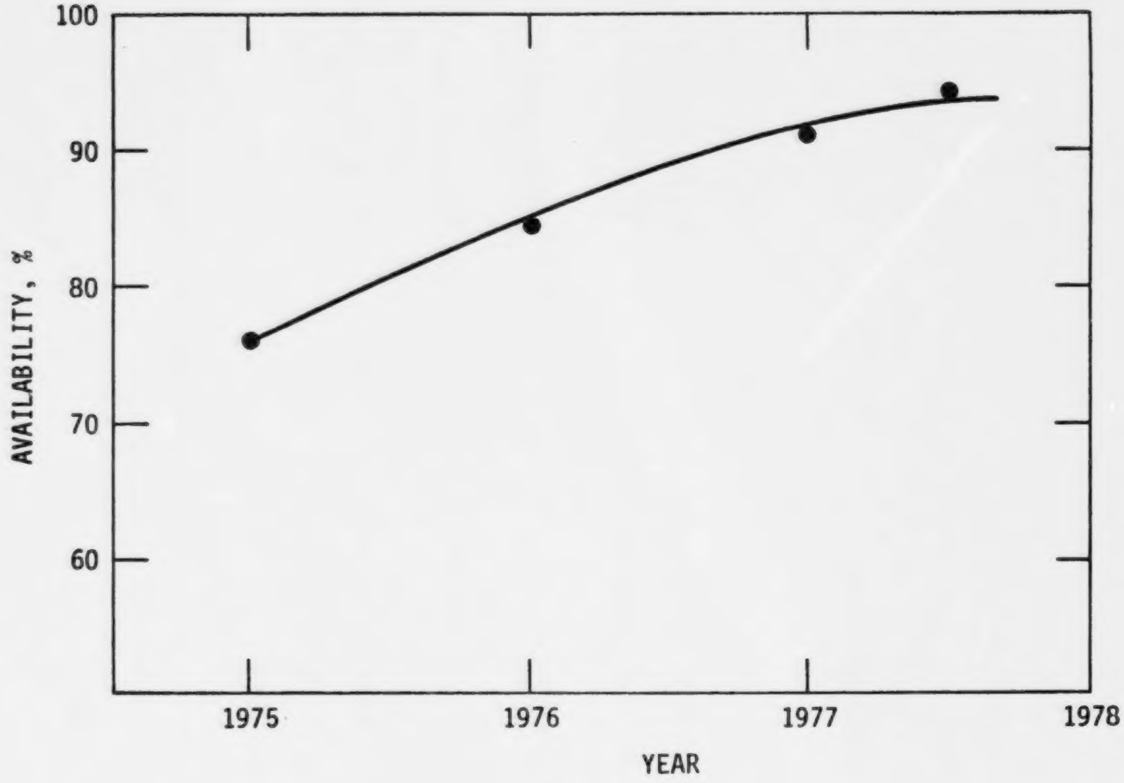


FIGURE 4-23

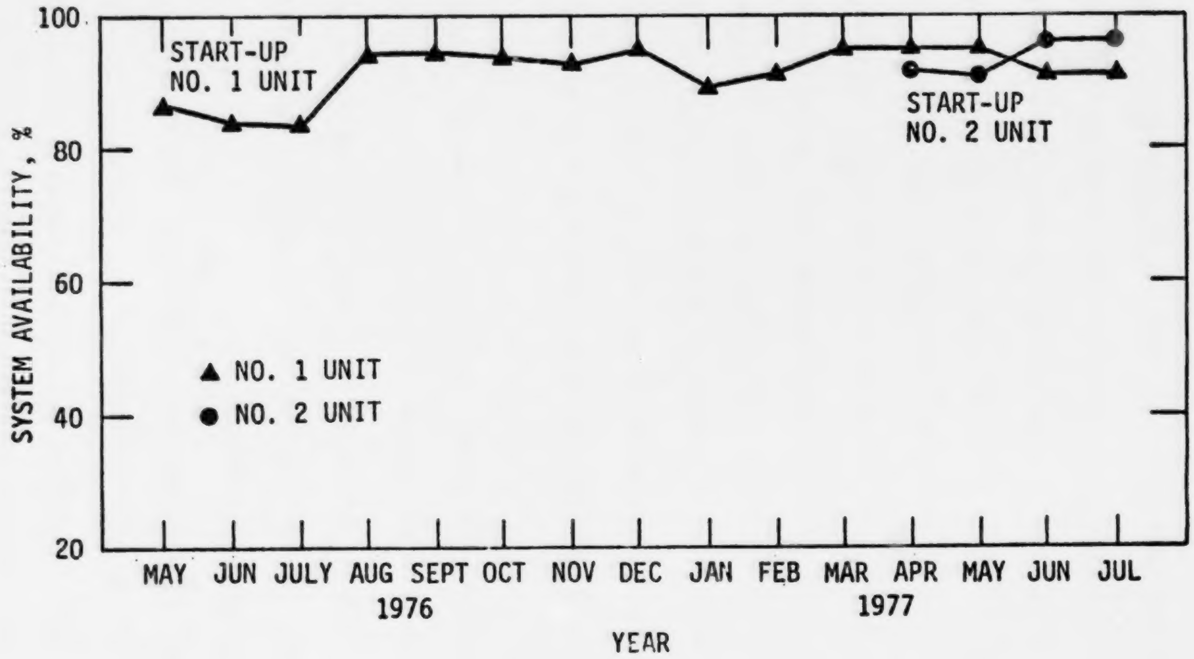
LA CYGNE AVAILABILITY HISTORY

SO_2 removal efficiency. Actual SO_2 efficiency has been 80.18 percent with the seven modules operating on 720 MW. Under maximum load, the removal efficiency averaged 76.2 percent. Efficiencies under both conditions should improve now that eight modules are operating.

The Northern States Power Co. Sherburne County Station No. 1 and No. 2 units both have 700 MW net capacity and burn 0.8 percent sulfur coal. Availability for Unit No. 1 averaged 85 percent for the four months of operation after startup. For the past 12 months, availability has been in excess of 90 percent. Unit No. 2 has shown even better startup performance, with operabilities averaging about 95 percent for the first 4 months. These data are shown in Figure 4-24. Table 4-19 shows pertinent operating data for the first 8 months of operation of No. 1 unit. The SO_2 removal efficiency was 50 to 55 percent, which was sufficient to meet local regulations.

Based on the operating experience of lime and limestone systems, (see Appendix D) there seems to be sufficient evidence to show that these systems can operate at 90 percent SO_2 removal or greater and that they can operate reliably (90 percent operability) with proper design and maintenance.

4.4.3.2 Sodium Carbonate Scrubbing. The sodium carbonate process accomplishes the removal of SO_2 from the stack gas by employing a clear water solution of sodium carbonate. As can be seen in Figure 4-25, a solution of soda ash (Na_2CO_3) reacts with SO_2 to form



Source: Source: PEDCo., 1977d.

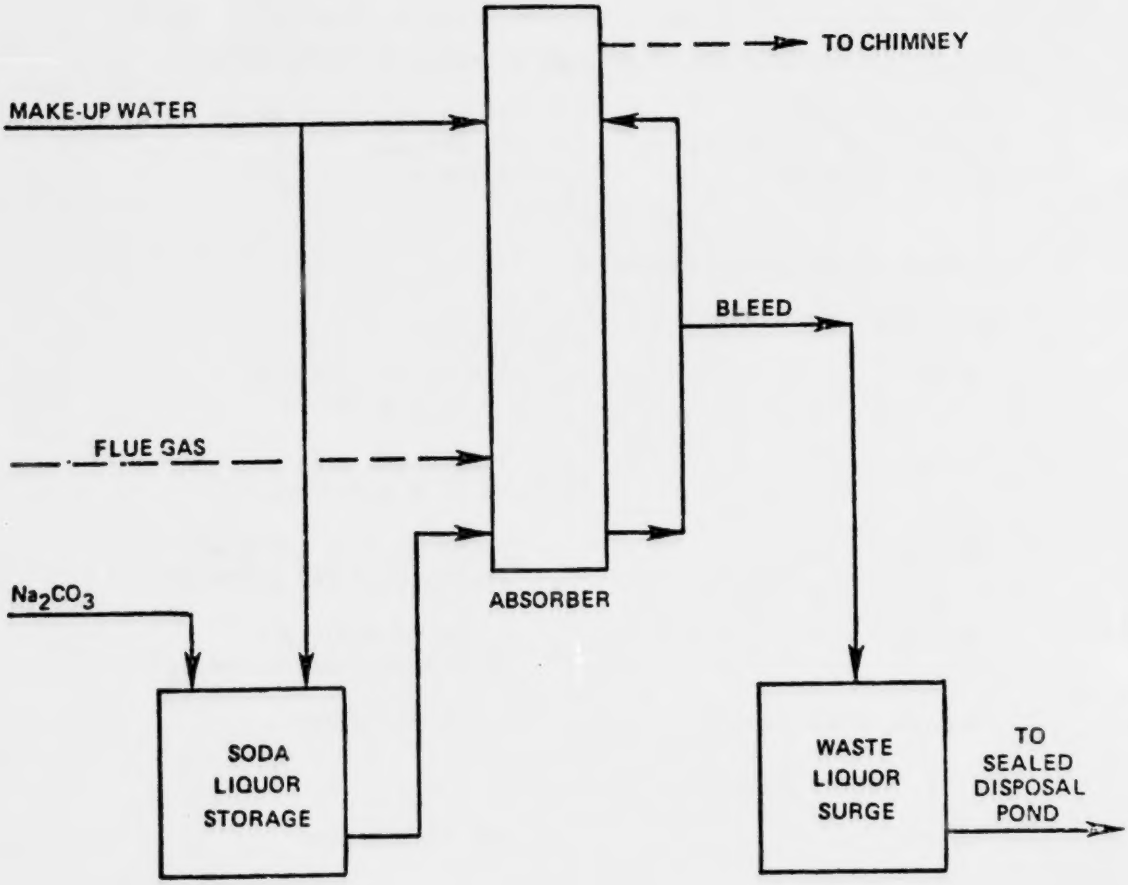
FIGURE 4-24
AVAILABILITY HISTORY
SHERBURNE NO. 1 AND NO. 2

TABLE 4-19

SHERBURNE COUNTY GENERATING PLANT
Unit 1 - Performance Data

I. Unit Data (based on May 1 through December 31, 1976 data)	
Electrical output	3,068,130 total MW-hr
Overall capacity factor	60 percent
On-line duration	5,176 hr
II. Scrubber System Data (Averages)	
Particulate concentration:	
Inlet	4.6 to 9.2 g/dry m^3 (2 to 4 gr/dscf)
Inlet	1.7 to 3.4 g/kJ (4 to 8 lb/MM Btu)
Outlet	0.080 to 0.10 g/dry m^3 (0.035 to 0.044 gr/dscf)
Outlet	0.032 to 0.036 g/kJ (0.075 to 0.085 lb/MM Btu)
Removal efficiency	98 to 99 percent
Sulfur dioxide concentration:	
Inlet	400 to 800 ppm
Inlet	0.730 to 0.859 g/kJ (1.7 to 2.0 lb/MM Btu)
Outlet	200 to 400 ppm
Outlet	0.370 to 0.41 g/kJ (0.85 to 0.95 lb/MM Btu)
Removal efficiency	50 to 55 percent

Source: PEDCo, 1977.


TO CHIMNEY
MAKE-UP WATER
BLEED
FLUE GAS
Na_2CO_3
ABSORBER
SODA LIQUOR STORAGE
WASTE LIQUOR SURGE
TO SEALED DISPOSAL POND

Source: Bechtel, November 1977.

FIGURE 4-25

SIMPLIFIED PROCESS DIAGRAM FOR
SODIUM CARBONATE SCRUBBING SYSTEM

sodium sulfite/bisulfite. Both the reactant and the reaction products are highly soluble in water. If fly ash is removed prior to SO_2 removal, the absorber can be either a packed tower or a tray tower, which has very high efficiency with low pressure drop. If fly ash is not removed, or is only partially removed, a venturi scrubber may be used for both particulate and SO_2 removals with somewhat lower absorption efficiency and higher presure drop. In either type of absorber, a recirculating liquid stream as well as fresh soda makeup is required to effect better gas-liquid contacting and better SO_2 removal. Since the sodium alkali is very reactive with SO_2, the required L/G ratios are generally low (in the 10 to 25 gal/mcf range). The system responds rapidly to changes in SO_2 loadings, and the soda feed rate can be controlled by pH signal from the absorber effluent, the pH changing with SO_2 loadings.

Table 4-20 is a summary of the sodium carbonate system, an important process consideration is the purging of the spent alkaline solution (sodium sulfite/bisulfite) in order to maintain the chemical balance. The purge rate can be controlled by the liquid density. This purge stream, usually slightly acidic, is neutralized with more soda alkali before disposal. Process water makeup is required to compensate for the water evaporated in the flue gas and lost in the purge stream.

In some arid areas, the spent alkali purge stream may be discharged to a sealed evaporation pond for drying. Alternative disposal methods include fixation of the scrubber effluents and

TABLE 4-20

SODIUM CARBONATE SCRUBBING EVALUATION

PARAMETERS	COMMENTS
Process complexity, operability, and reliability	Extremely simple, easy to operate, high degree of reliability
Process performance	SO_2 removal capability high (better than 90 percent)
Waste/product	Disposal of spent alkali solution requires extensive evaluation
Development status	Full-scale operation on coal-fired boilers
Advantages/disadvantages	No scrubber scaling, low L/G ratio, minimal corrosion and erosion, can tolerate fly ash in the system; limited applicability because of expensive alkali

the recovery of sodium sulfate (salt cake) for sale. If permitted by local regulations, ponding may be the most economical method.

The system consumes a premium chemical, either caustic soda or soda ash; therefore, its application is limited to small industrial boilers or utility boilers located near an inexpensive source of the alkali. System advantages are simplicity, very high SO_2 removal efficiency, low capital cost, and good system operability and reliability. Disposal of the spent alkali solution requires careful consideration.

A prototype unit, serving two industrial coal-fired boilers (equivalent to 25 MW) at the General Motors assembly plant in St. Louis, has been in operation since 1972. The system availability has been greater than 90 percent. Three 125 MW units at Nevada Power Company's Reid Gardner Station are operating with low sulfur coal. System availability has ranged from 70 to 99.4 percent (Bechtel, 1977) typically about 90 percent.

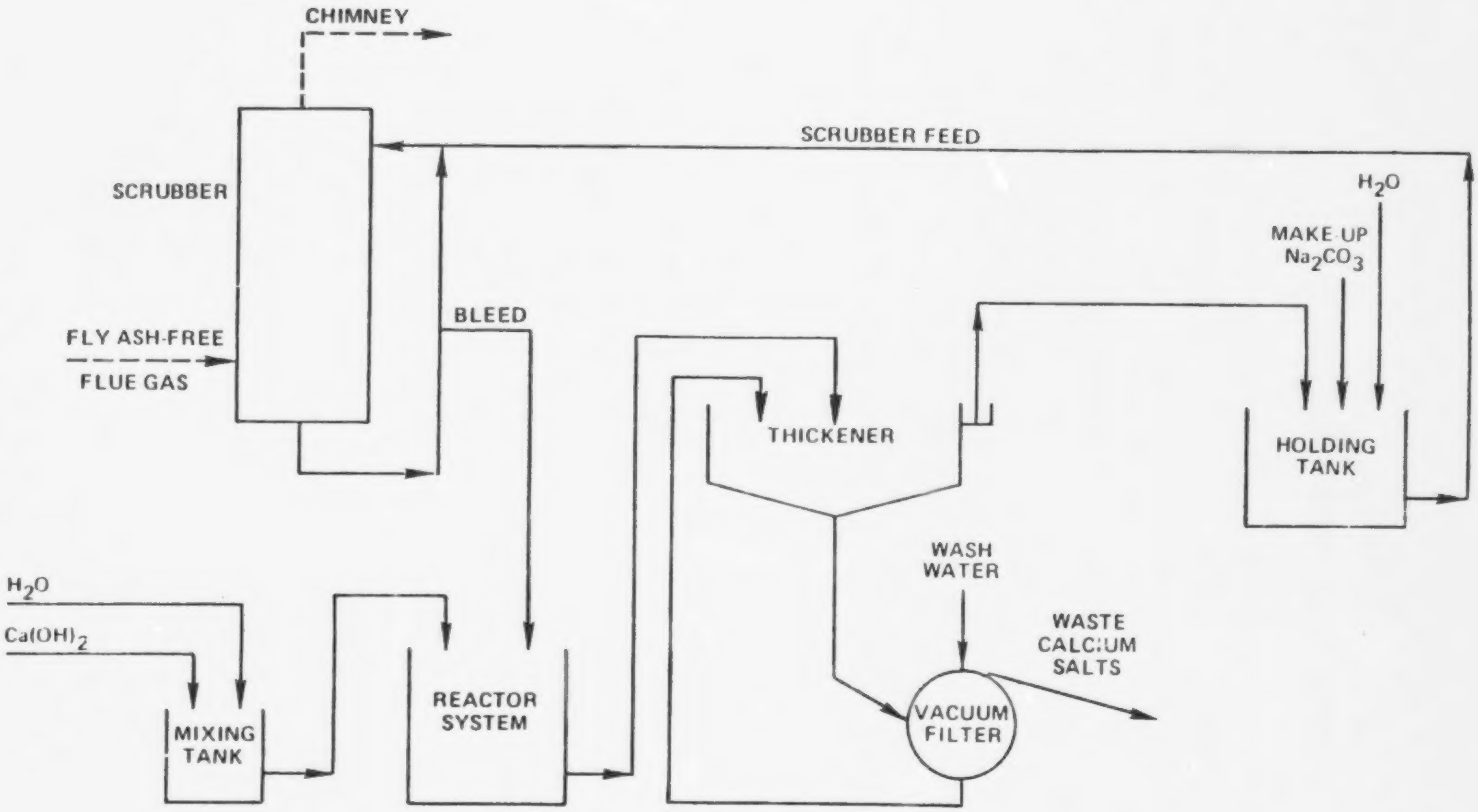
4.4.3.3 Double Alkali (Soda-Lime) Scrubbing. This FGD process is a combination of sodium carbonate and lime or limestone processes. The double alkali system is similar to the lime or limestone system in that lime or limestone is used and a calcium sulfite/sulfate and fly ash wet solid product is the result. However, a number of intermediate steps are added. The SO_2 is absorbed by a clear sodium sulfite solution to produce soluble sodium bisulfate which is later reacted with lime or limestone to produce the system waste product in the form of an insoluble calcium salt and to regenerate the sodium sulfate. Hence, absorption and waste product functions are separated. The results of the two-stage system is that scrubbing can be accomplished by a solution instead of a slurry. This will increase reliability by reducing scale and plugging within the scrubber. The system also increases both the utilization of the sorbent and SO_2 removal efficiency. The waste is essentially the same as the lime/ limestone sludge. Figure 4-26 shows a typical process flow chart for a double alkali system.

The double alkali system is designed to combine desirable properties of other FGD processes. This FGD process has the high SO_2 absorption and nonscaling characteristics of the clear liquid sodium carbonate process and avoids disposal problems of sodium salt waste.

A summary of the double alkali system is presented in Table 4-21. One of the main problems associated with the double alkali system is the regeneration of sodium sulfate (Na_2SO_4). Sodium sulfate does not react well with hydrated lime in the presence of sodium sulfite (Na_2SO_3).

The sodium sulfate is formed by oxidation of sodium sulfite in the absorber. Regeneration of Na_2SO_4 can be improved in two ways:

- Minimize sodium sulfate formation by minimizing oxidation through the use of a concentrated absorbing solution.
- Employ a dilute absorbing solution to reduce the amount of sodium sulfite, and increase oxidation since in the absence of the sulfite sodium sulfate will react with lime to precipitate calcium sulfate.


CHIMNEY
SCRUBBER
SCRUBBER FEED
FLY ASH-FREE
FLUE GAS
BLEED
H_2O
MAKE-UP
Na_2CO_3
THICKENER
HOLDING
TANK
H_2O
$Ca(OH)_2$
MIXING
TANK
REACTOR
SYSTEM
WASH
WATER
WASTE
CALCIUM
SALTS
VACUUM
FILTER

Source: Bechtel, November 1977.

FIGURE 4-26

SIMPLIFIED PROCESS DIAGRAM FOR
DOUBLE ALKALI SYSTEM

TABLE 4-21

DOUBLE ALKALI PROCESS EVALUATION

PARAMETERS	COMMENTS
Process complexity, operability, and reliability	Process is somewhat complex and requires more components than the lime/limestone processes; operability and reliability are expected to be greater than lime or limestone FGD processes.
Process performance	SO_2 removal capability greater than 90 percent.
Waste/product	Disposal of calcium sludge; additional problem of sodium sulfate purge is required.
Development status	Full-scale operation on oil-fired boilers in Japan; prototype operation coal-fired in the U.S.; full-scale units under construction in the U.S.
Advantages/disadvantages	Minimizes scrubber scaling; low liquid to gas ratio; no product to market; requires two or three separate solids handling systems.

Most operating experience to date has been based on 700 MW from about 12 installations operating on oil or coal-fired industrial boilers in the U.S. and Japan, three utility oil-fired industrial boilers in Japan totaling 1,050 MW and a 20-MW prototype coal-fired utility boiler developed for testing by Gulf Power Company in Florida. There are currently three double alkali processes scheduled for operation in 1979 on coal-fired utility boilers.

Several successful bench-scale, pilot plant and prototype double alkali FGD systems have been tested on boiler flue gas applications in the U.S. The success of these programs has resulted in commitments by three separate electric utility companies to install full-scale double alkali FGD systems on coal-fired boilers. As yet no full-scale system is operating on a utility boiler in the U.S; but several systems are working on coal-fired industrial boilers, and one pilot plant system and one prototype have been tested on utility units.

Applications on industrial boilers are as follows:

Company: General Motors, Inc.
Plant: Chevrolet Parma
Location: Parma, Ohio
Stream treated: Off-gas from coal-fired boilers
System size: 124 m^3/s (262,000 acfm) (32 MW)
SO_2 inlet: 800 to 1300 ppm (1.5 to 3.0 percent S coal)
Startup date: March 1974

Company: Caterpillar Tractor Co.
Plant: Joliet Plant
Location: Joliet, Illinois
Stream treated: Off-gas from coal-fired boilers
System size: 48.8 m^3/s (103,500 acfm) (18 MW)
SO_2 inlet: 2300 ppm (4 percent sulfur coal)
Startup date: September 1974

Company: Firestone Tire and Rubber Co.
Plant: Pottstown Plant
Location: Pottstown, Pennsylvania
Stream treated: Off-gas from a oil-fired boiler
System size: 6.6 m^3/s (14,000 acfm)
SO_2 inlet: 1,000 ppm
Startup date: January 1975

Company: Caterpillar Tractor Co.
Plant: Mossville Plant
Location: Mossville, Illinois
Stream treated: Off-gas from 4 coal-fired boilers
System size: 113 m^3/s (240,000 acfm) (57 MW)
Fuel properties: Coal, 3.2 percent sulfur average
Startup date: October 1975

One prototype and one pilot plant double alkali system have operated on utility coal-fired boilers:

Utility: Utah Power and Light Co.
Unit: Gadsby Station, Unit No. 3
Location: Gadsby, Utah
Unit size: 1.2 m^3/s (2500 acfm) (0.6 MW)
Fuel properties: Coal, 0.4 percent sulfur average
Startup date: 1971
Note: Terminated 1973

Utility: Gulf Power Co.
Unit: Scholz, Unit No. 1
Location: Chattahoochee, Florida
Unit size: 35 m^3/s (75,000 acfm) (20 MW)
Fuel properties: Coal, 3 to 5 percent sulfur
Startup date: February, 1975
Note: Terminated July 1976

As a result of the success of pilot and prototype systems, three full-scale double alkali systems are scheduled for operation soon on new coal-fired utility boilers.

The GM Parma system has performed well with regard to SO_2 removal. Results of a 1-week test in 1974 indicate SO_2 removal efficiencies in the 94- to 99-percent range, with relatively low inlet SO_2 levels (600 to 1200 ppm) and high excess air rates. A test was conducted by A. D. Little, Inc., and General Motors (GM) from August 19, 1974 to May 14, 1976. It consisted of three 1-month intensive test periods and 18 months of lower-level tests. Removal of SO_2 reflects the variations in operating modes employed by GM during the period, but removal efficiencies were at 90 percent for the viable operating modes. Operation during April and May 1976 was excellent and A. D. Little, Inc., recommended continued operation in the mode used during this period.

The operability (hours the FGD system was operated per boiler operating hours in a period expressed as a percentage) of the Parma system for the 1-year period from May 1976 through April 1977 was about 70 percent. The system's best period of operation was May through August 1976, when operability averaged 94 percent. The GM Parma plant has several unique characteristics that affect operability. Each boiler is equipped with its own separate scrubbing module with no provision for crossflow between modules. The plant is not needed during the summer months, because operations are shut down during automobile model changes and because there is no need for heating. United Automobile Workers personnel operate the scrubber plant, which precludes operation of the scrubbers when they are not on the site. The GM plant is a developmental system, and as such is subject to modifications. Many of the low operability periods were due to mechanical outages or outages for modifications to accommodate and test new modes of operation. Several different operating modes have been investigated, and significant improvements have been obtained in both process and mechanical performance. Although it has yet to be proved over an extended test period, it is believed that in the latest operational mode the system is capable of long-term reliability.

The Joliet system has achieved excellent SO_2 removal efficiencies of between 85 and 95 percent under various operating conditions. Sulfur dioxide inlet concentrations are high, about 2300 ppm. The system was designed to attain an emission level of 860 ng/J (1.9 lb $SO_2/10^6$ Btu) (75 percent SO_2 removal), but has consistently performed much better than designed.

The operability of the FGD system has been improving steadily. Process availability for the period October 24, 1975, through June 1976 has been 100 percent. Most problems at the Joliet plant are mechanical; the majority are solved while still on-stream or during scheduled shutdowns. As a consequence, there have been few forced outages.

The Firestone-Pottstown system has exhibited excellent SO_2 removal efficiencies of 90 percent on high-sulfur oil, but no data are available for its performance on coal. It has also achieved a very high availability: 99 percent for the first 12 months of operation. Most downtime periods were due to mechanical component failure or to maintenance, and not to unwanted chemical changes or side reactions. No scaling problems have been experienced.

The Gadsby scrubbing system has performed well with respect to SO_2 removal. Various modes of operation were tested using two types of absorbers. With the polysphere absorber, SO_2 removals of 90 percent were achieved, giving outlet concentrations of 15 to 40 ppm SO_2. With the venturi absorber, efficiencies ranged from 80 to 85 percent SO_2 removal.

With the exception of the first 3-month operating period, during which some gypsum scaling problems were encountered, dilute mode operations were conducted for almost 2 years without any major problems. No operating problems causing shutdown were experienced between October 1972 and August 1974. For convenience, the system was shut down on weekends, but no drainage of solution or cleaning of equipment took place during these shutdowns.

The Gulf-Scholz prototype system started up February 3, 1975, and operated continuously through July 18, 1975, when it was shut down for repairs and modifications. The second period of operation was from September 16, 1975, through January 2, 1976.

The system exhibited excellent SO_2 removal capabilities, of 90 percent and greater. Using the combined venturi/absorber configuration at a venturi liquor pH above 5.2, outlet SO_2 concentrations below 50 ppm were achieved, which corresponds to greater than 95-percent removal. Raising the pH of the venturi liquor above 6.0 resulted in SO_2 removal efficiencies greater than 98 percent.

The operability of the Scholz plant for the period February 1975 through June 1976 is presented in Table 4-22. The Scholz plant was designed to demonstrate the viability of the double alkali process technology for application on utility coal-fired boilers. As such, this prototype plant had less spare equipment than would be normal in full-scale applications. The operability of the system has been steadily improved; during the last 4 months of operation, it was 94 percent.

Although no full-scale double alkali FGD systems are in operation on coal-fired utility boilers, it is possible to predict operability of the systems, based on experience with smaller units on coal-fired industrial boilers described here. The operability of double alkali FGD systems on coal-fired utility boilers and prototype utility installations has been improved steadily; it is now 90 percent and above. Most operability problems were due to design-related equipment shortcomings in these prototype installations. It should be pointed out that most installations did not have spare equipment; however, this would be included in full-scale utility systems.

TABLE 4-22

CEA/ADL DOUBLE ALKALI PROTOTYPE SCRUBBER PERFORMANCE HISTORY: OPERATION AND VIABILITY PARAMETERS

Period	Total period, hr	Boiler operation, hr	FGD operation, hr	FGD[a] operability, percent	FGD[b] utilization percent
Feb. 75	672	459	454	98.9	67.6
Mar. 75	744	507	485	95.7	65.2
Apr. 75	720	604	336	55.6	45.2
May 75	744	598	375	63.2	50.4
Jun. 75	720	720	720	100.0	100.0
Jul. 75	744	683	221	32.4	29.7
Aug. 75	744	744	0	0	0
Sep. 75	720	577	254	44.0	35.3
Oct. 75	744	559	559	100.0	75.1
Nov. 75	720	620	560	90.3	77.8
Dec. 75	744	732	732	100.0	98.4
Jan. 76	744	0	0	0	0
Feb. 76	696	0	0	0	0
Mar. 76	744	480	445	92.7	59.8
Apr. 76	720	642	616	95.9	85.6
May 76	744	735	651	88.6	87.5
Jun. 76	720	656	641	97.7	89.0

[a] FGD operability: The number of hours the FGD system was in operation divided by the number of hours the boiler was in operation, expressed as a percentage.

[b] FGD utilization: The number of hours the FGD system was in operation divided by the number of hours in the period, expressed as a percentage.

Source: PEDCo, 1977d.

Equipment-related problems were solved at each of the double alkali installations and the experience gained will benefit later installations. The vendors of double alkali systems have developed confidence in their reliability: as evidenced by guarantees of 90-percent availability for the first year of operation and 100 percent for the life of the plant (based on a boiler operating rate of 70 percent for some of the new, full-scale utility applications). The systems are all guaranteed to achieve 85 to 95 percent SO_2 removal efficiency on high-sulfur coal applications. No new low-sulfur coal applications are planned, but similar guarantees would be expected for such systems.

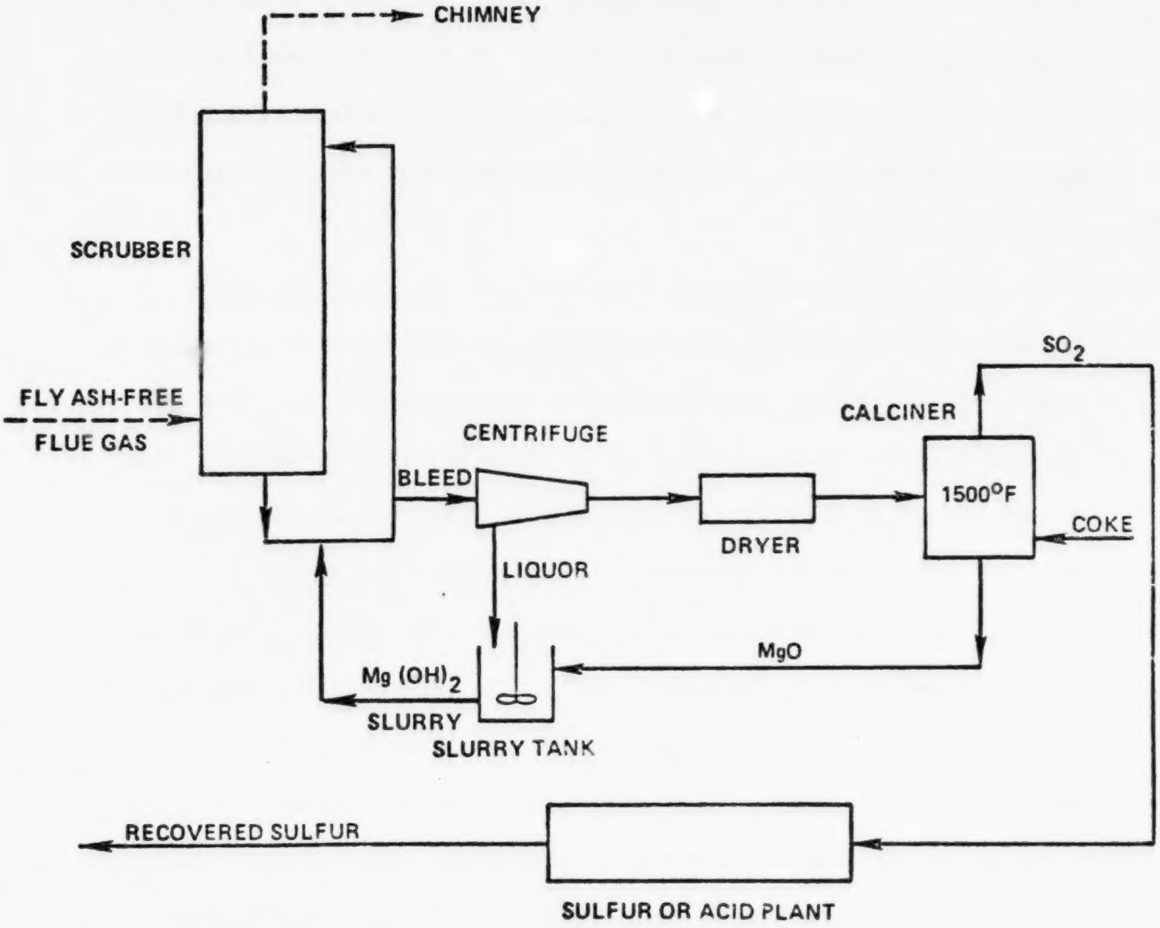
Corrosion, erosion, and scaling problems have not been important factors at double alkali FGD installations. Full-scale versions of these systems are not expected to experience these problems either. The double alkali system has demonstrated the ability to perform well under fluctuating SO_2 inlet concentrations. At the Scholz plant, the design inlet SO_2 concentration was 1,800 ppm. At inlet concentrations varying from 800 to 1,700 ppm, removal efficiencies were above 90 percent.

4.4.3.4 Magnesium Oxide Scrubbing. The magnesium oxide scrubbing process is a wet slurry scrubbing regenerable process that differs from the lime process in two basic ways: the magnesium sulfite produced when SO_2 is absorbed from the flue gas can be calcined to recover the SO_2 in concentrated form, and during calcining the magnesium oxide

(MgO) is regenerated and can be recycled. The results are the process produces a marketable product with no sludge to dispose of; and secondly, there is only a small chemical makeup required. The magnesium oxide process has not had the scaling problems of the lime/limestone processes because magnesium sulfite and sulfate are orders of magnitude more soluble at normal scrubber temperatures than their calcium counterparts.

Figure 4-27 is a typical flow chart of the magnesium oxide process. The magnesium oxide scrubbing requires particulate matter removal prior to the flue gas entering the absorber. The flue gas is next scrubbed with a slurry of 10 percent solids by weight. The MgO reacts with the SO_2 to form magnesium sulfite hydrates and as portions of the sulfite are oxidized to the sulfate form.

The hydrated magnesium sulfite/sulfate ($MgSO_3/MgSO_4$) crystals are withdrawn from the scrubbing cycle in a side stream containing about 10 percent solids. This portion of the slurry goes to a dewatering system (centrifuge) where the separate liquid is recycled to the absorber and the solids in the form of a wet coke are transferred to a dryer. The dried crystals are reacted with a reducing agent (carbon) and calcined in a reducing atmosphere at about 1500°F to produce concentrated SO_2 and MgO. The reducing agent is required to reduce the sulfate. The SO_2 rich stream can then be used (after dust removal) for production of a sulfur or sulfuric acid by-product. The MgO is recycled to the scrubber system.


CHIMNEY
SCRUBBER
FLY ASH-FREE
FLUE GAS
BLEED
CENTRIFUGE
LIQUOR
DRYER
CALCINER
1500°F
COKE
SO_2
MgO
$Mg(OH)_2$
SLURRY
SLURRY TANK
RECOVERED SULFUR
SULFUR OR ACID PLANT

Source: Bechtel, 1977.

FIGURE 4-27

SIMPLIFIED DIAGRAM FOR MAGNESIUM OXIDE RECOVERY SYSTEM

A summary of the magnesium oxide system is presented in Table 4-23. The major problems encountered with the magnesium oxide system have been: (1) the formation of trihydrated sulfite crystals in the scrubber as opposed to the hexahydrate crystals that are easier to handle, (2) erosion of pumps valves and piping, (3) dust from the dryer, and (4) excessive wear on internal parts of the centrifuge. However, proper material choice and good operation and maintenance practices will minimize some of these problems.

An added advantage for the magnesium oxide process is the potential for a central regeneration facility to serve several FGD systems. This is possible because the dry magnesium sulfite is stable and easy to transport.

Three full size units have been operated in the United States:

Utility name: Boston Edison
Unit name: Mystic Station, No. 6
Unit location: Everett, Massachusetts
Unit size: 155 MW
Fuel properties: No. 6 Fuel Oil, 2.5 percent sulfur
Startup date: April 1972
Demonstration terminated: June 1974

Utility name: Potomac Electric and Power
Unit name: Dickerson No. 3
Unit location: Dickerson, Maryland
Unit size: 95 MW
Fuel properties: Coal, 2.0 percent sulfur
Startup date: September 1973
Demonstration terminated: August 1975

Utility name: Philadelphia Electric
Unit name: Eddystone No. 1A
Unit location: Eddystone, Pennsylvania
Unit size: 120 MW
Fuel properties: Coal, 2.5 percent sulfur
Startup date: September, 1975
Suspended operation in January 1976 pending relocation of calciner after acid plant shutdown. Restarted in June 1977.

TABLE 4-23

MAGNESIUM OXIDE SCRUBBING

PARAMETER	COMMENTS
Process complexity, operability, and reliability	A complicated chemical operation unfamilar to the utility industry, however the regeneration system can be separated from the scrubber at the power plant.
Process performance	SO_2 removal capability greater than 90 percent.
Wastes/product	Produces sulfuric acid or sulfur for sale; sulfur poses minimal disposal problems.
Advantages/disadvantages	No scaling in system; oxidation can be tolerated; must operate acid plant; marketing of acid may be problem; fly ash must be kept out of regeneration system; losses and deactivation of MgO may occur by repeated regeneration.

Since the Mystic Station Unit No. 6 employed oil as its fuel, no particle collection was required prior to the scrubber. The scrubber did an excellent job of SO_2 removal. Test data indicate an average removal efficiency of over 91.6 percent. This was achieved at gas flow rates ranging from 12,036 m^3/min (425,000 acfm), which was the design value, to 18,640 m^3/min (658,000 acfm), more than 54 percent in excess of the design value. Outlet SO_2 concentrations averaged 82.7 kg/J (0.192 lb/10^6 Btu).

The operability of the No. 6 Unit at Mystic for the entire test run is presented in Table 4-24. Operability is defined as hours of FGD operation divided by hours of boiler operation in a given period, expressed as a percentage. The unit worked best during its last 4 months, when operability was about 80 percent. It would have been approximately 85 percent but for a 2-week outage of the off-site sulfuric acid plant. The FGD system had to shut down since MgO could not be regenerated. From April 12 to May 10, 1974, the system achieved 100 percent operability.

The operation showed that magnesium oxide scrubbing for sulfur oxide removal is technically feasible. The scrubber performed at or above the design efficiency (90 percent) at gas flow rates 50 percent over design. Slurry solids separation was achieved and magnesium sulfate concentration controlled. No plugging and scaling occurred.

The boiler at the Dickerson Station Unit No. 3 burned 2 percent sulfur coal. Flue gas from the boiler normally passed through an

TABLE 4-24

OPERABILITY OF MgO SYSTEM AT MYSTIC NO. 6

Month/yr	Boiler operation (hr)	Scrubber operation (hr)	Operability	Comments
Apr. 72 to May 73			17	The module operated intermittently because of mechanical difficulties. Operation of the magnesium sulfite crystals dryer presented a major problem.
Jun. 73	592	402	68	The longest period of continuous operation, 7.5 days, occurred during June and July.
Jul. 73	575	351	61	
Aug. 73		Boiler shutdown		The boiler was down for the annual overhaul. System operability decreased during the last quarter of the year because of heavy erosion/corrosion in the liquor recirculation pumps and centrifuge.
Sep. 73	637	243	38	
Oct. 73	627	377	60	
Nov. 73	629	162	26	
Dec. 73	658	86	13	
Jan. 74	555	152	28	Boiler-related problems caused frequent shutdowns in January and February.
Feb. 74	541	138	25	
Mar. 74	408	353	87	
Apr. 74	585	471	81	Two 7-day, continuous operation periods occurred during the month.
May 74	488	280	57	The 57-percent operability index value for the month was due to a 2-week outage of the acid plant rather than to FGD system failure.
Jun. 74	559	288	80	
Test period completed				Demonstration program was completed and FGD system was shut down. EPA funding of $MgSO_3$ calcination has expired. There are no definite plans for restarting of this unit. Major problem areas encountered during the operation of this prototype unit included formation of trihydrate instead of hexahydrate sulfite crystal, dust problems in the dryer, lack of stack gas reheat, which caused condensation in the stack, louver damper problems, erosion of pumps, piping, and centrifuge, and minor ancillary equipment failures.

Source: PEDCo., 1977d.

ESP for fly ash removal before entering a two-stage venturi scrubber/ absorber. The MgO system was tested both with and without the ESP, which can be bypassed. Dickerson Unit No. 3 achieved an average SO_2 removal efficiency of 88.9 percent during performance testing (Table 4-25). If the one low result were omitted, the average would be 90.4 percent.

The operability of this MgO FGD system, defined as hours of operation divided by boiler operating hours, is shown in Table 4-26. The unit was a prototype trial installation, built to obtain operating data and not necessarily for long-term operability. As such, equipment and materials were used that would not have been used in a long-term installation on a new plant. This operation fulfilled its purpose by showing areas where improvement was needed. The operability data shows the downtime caused by mechanical and material failures.

TABLE 4-25

SO_x EMISSIONS TEST RESULTS FOR MgO FGD SYSTEM - DICKERSON[a]

Test Series	Δ P,[b] cm	(in.) H_2O	SO_2, ppm		SO_2 Removal,	SO_3, ppm	
			Inlet	Outlet	percent	Inlet	Outlet
5A	38.4	(15.1)	779	78	90	34.6	3.56
5B	16.8	(6.6)	1373	157	88.7		
6	13.0	(5.1)	800	137	82.9	47.5	3.31
7	37.3	(14.7)	1418	88	93.9	2.9	0.64
8	13.2	(5.2)	1419	156	89.0	1.8	0.41

[a] Test results abstracted from York Research Corporation, Final Report, Y-8513, January 31, 1975.

[b] Second Stage (absorber) pressure drop.

Source: PEDCo, 1977d.

TABLE 4-26

OPERABILITY DATA FOR DICKERSON NO. 3

TIME PERIOD	OPERABILITY, PERCENT
September 13, 1973 - January 14, 1974	27.4
December 9, 1973 - January 14, 1974	58.3
April 15, 1974 - May 1, 1974	40.5
August 1, 1974 - August 31, 1974	43.5
November 1, 1974 - November 30, 1974	44.6
November 15, 1974 - November 30, 1974	67.9
December 1, 1974 - December 31, 1974	57.9
Test Runs Completed August, 1975	

Source: PEDCo., 1977d.

The Eddystone facility scheduled for startup in 1975 had to be temporarily shut down in January of 1976 because Olin Chemical closed the acid plant serving the MgO calciner. The regeneration equipment was relocated to Essex Chemical, Newark, New Jersey. Although the Eddystone FGD system operated only a short time, it removed more than 90 percent of the SO_2 when both trays of venturi rods in the SO_2 absorber were used and when the L/G was 6689 litres per am^3/min (50 gal/1000 acfm). Eddystone must meet an SO_2 emission standard of 260 ng/J (0.6 lb $SO_2/10^6$ Btu).

The operability data available are limited to the startup down phase. Over the period October 2, 1975, through December 31, 1975, operability of the SO_2 scrubber was only 33 percent. During the recent startup the main problems were with ancillary equipment; the major equipment, scrubbers and absorber, etc., worked properly.

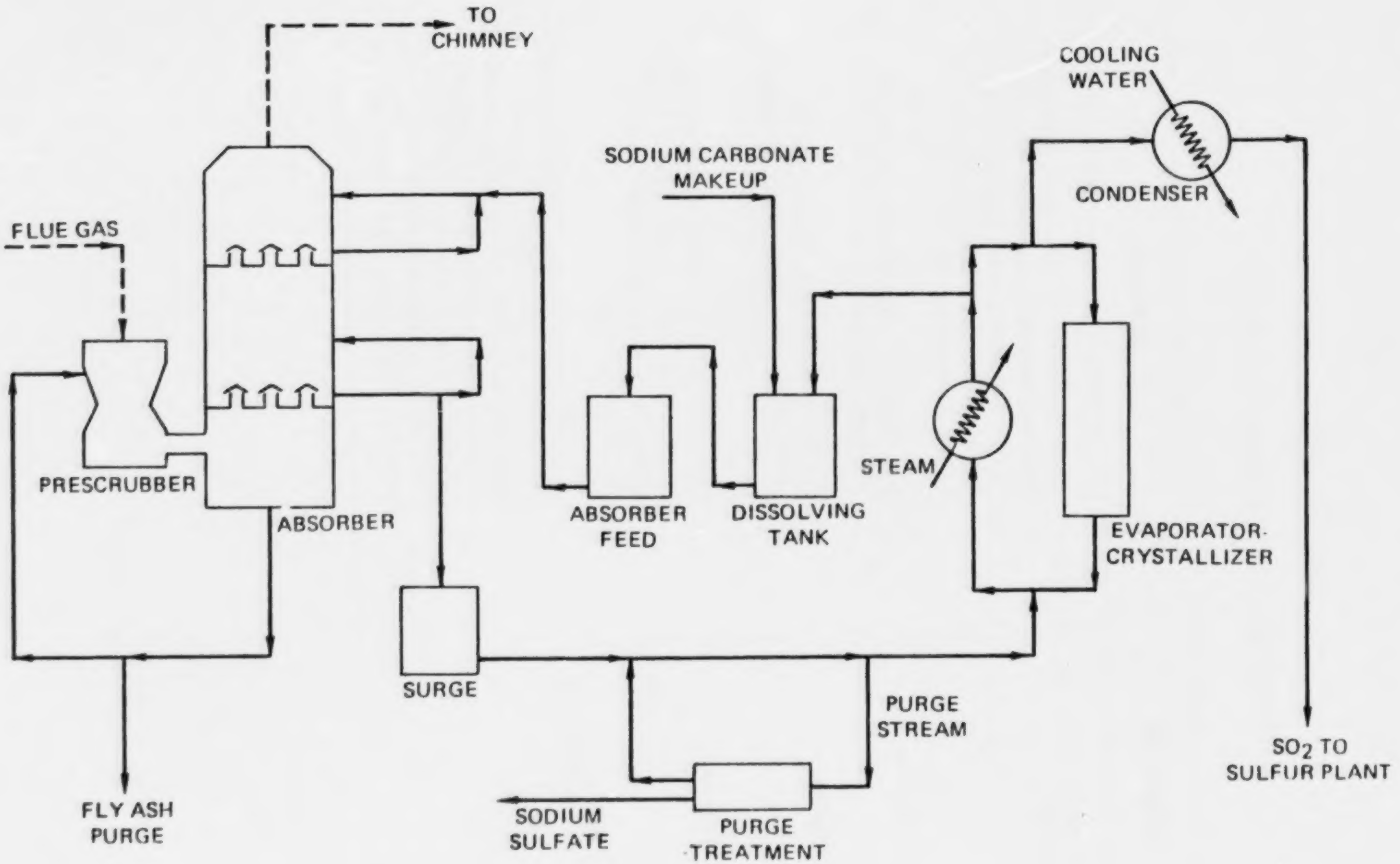
The two Chemico MgO FGD systems (oil-fired at Mystic; coal-fired at Dickerson) were prototype units, built to demonstrate the potentials of the process and to determine the major areas for improvement. The venturi was adopted for use in these prototypes. The units were built on a low budget and include little redundancy, to enable a high percentage of on-stream time.

4.4.3.5 Sodium Sulfite. The sodium sulfite (Wellman-Lord) process utilizes a clear liquid of sodium alkali with thermal regeneration of the sorbent and generation of sulfuric acid or elemental sulfur as a by-product. Figure 4-28 is a flow chart of the sodium sulfite regenerable FGD process.

The flue gas entering the absorber is scrubbed with a sodium sulfite liquid. The sodium sulfite reacts with the SO_2 in the flue gas to yield sodium bisulfite. The cleaned flue gas is reheated and directed to the stack.

The sodium bisulfite is decomposed to sodium sulfite (solid) and SO_2 (gas) in a forced-circulation evaporator-crystallizer. The sodium sulfite crystals are separated in a clarifier and redissolved in water prior to recycling to the absorber. Sodium sulfate formed by oxidation of sodium sulfite in the system cannot be decomposed and must be purged from the system. The concentrated SO_2 stream (90 percent SO_2, 10 percent H_2O) is directed to a sulfuric acid plant or sulfur plant.

Table 4-27 is a summary of the sodium sulfite process. The removal of particulate matter from the flue gas prior to the sodium sulfite absorber is a necessity. The liquid may have to be filtered along with good particulate removal in order to assure reliable operation. The oxidation of sodium sulfite to sodium sulfate is also a problem. Five to 10 percent of the incoming sulfur is lost as soluble sodium sulfate in the purge stream along with expensive reactant. The lost reactant must be made up with soda ash or caustic soda and the purge stream must be disposed.


TO CHIMNEY
COOLING WATER
FLUE GAS
SODIUM CARBONATE MAKEUP
CONDENSER
STEAM
PRESCRUBBER
ABSORBER
ABSORBER FEED
DISSOLVING TANK
EVAPORATOR-CRYSTALLIZER
SURGE
PURGE STREAM
SO_2 TO SULFUR PLANT
FLY ASH PURGE
SODIUM SULFATE
PURGE TREATMENT

Source: Bechtel, 1977.

FIGURE 4-28

SIMPLIFIED PROCESS DIAGRAM FOR
WELLMAN LORD RECOVERY SYSTEM

TABLE 4-27

SODIUM SULFITE SCRUBBING EVALUATION

PARAMETER	COMMENTS
Process complexity, operability, and reliability	This process is the most successful regenerable process for oil-fired boilers, availability has been excellent; the system is being demonstrated on coal.
Process performance	SO_2 removal capability greater than 90 percent.
Wastes/products	System produces sulfuric acid on sulfur for sales plus a small amount of liquid waste.
Development status	The system is full demonstration oil-fired units; full scale demonstrations on coal-fired boilers are in progress.
Advantages/disadvantages	No scaling in systems; low liquid/gas ratio in absorber; fly ash must be kept out of system; corrosive process environment requires expensive materials of construction; high steam consumption; requires soda make up.

The sodium sulfite (Wellman-Lord) process has been in operation on two oil-fired 35-MW industrial boilers in Japan since August 1971. The availability has been close to 100 percent. Two larger oil-fired systems, a 220-MW utility boiler and a 125-MW equivalent industrial boiler started up in Japan in 1973, have both been operating successfully. The first full-scale coal-fired EPA supported demonstration of the process is operational at Northern Indiana Public Service Company 115-MW Mitchell Station. Two other units totaling 715 MW are under construction in New Mexico.

Seven Wellman-Lord systems are currently in operation in the United States. Six units are installed on sulfuric acid or Claus sulfur recovery units. The gas flow rates on these are small, 51,000 to 133,000 nm/hr (30,000 to 78,000 scfm), in comparison with a new 500-MW coal-fired boiler with a gas flow rate of 1,700,000 nm^3/hr (1,000,000 scfm). The inlet SO_2 concentrations on the seven small units range from 2,700 to 10,000 ppm, which is about one to five times the SO_2 concentration expected with a 3.5-percent sulfur coal-fired boiler. The smaller units, however, operate on fairly clean, dry streams with low oxygen concentrations in comparison with boiler flue gases.

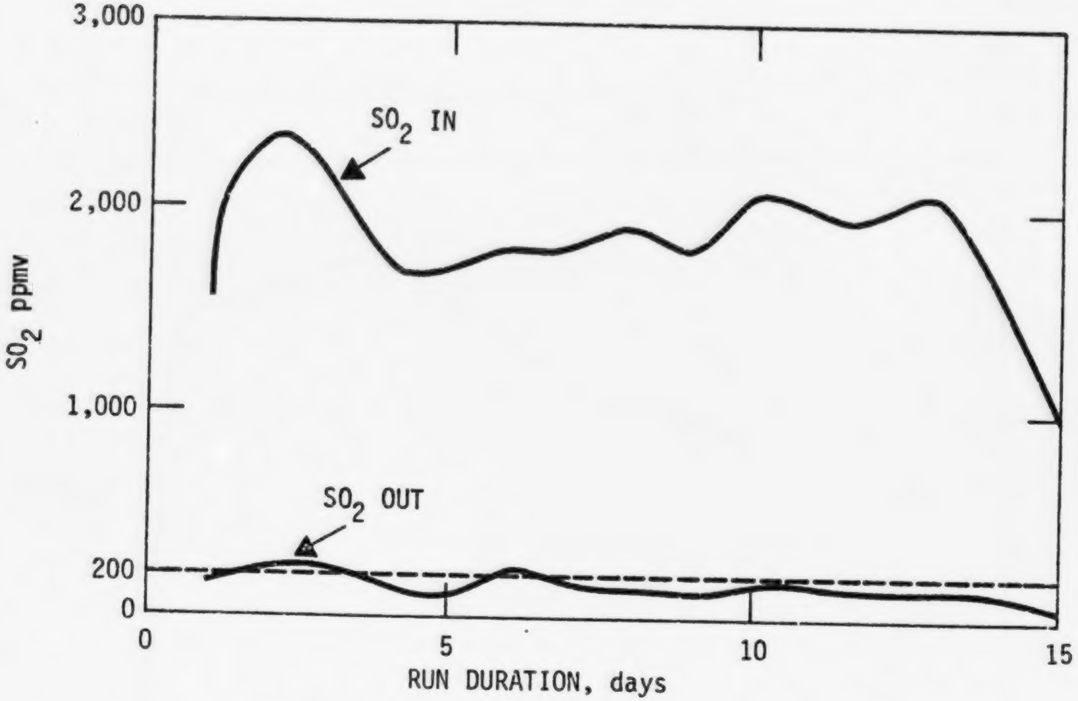
The SO_2 removal efficiency of the six units is typically 90 percent or greater; removal efficiencies in excess of 97 percent are reported. The collected SO_2 is either recycled to the sulfuric acid or Claus sulfur unit. Little operational data are available; it is reported, however, that the six units have absorber on-stream times of greater than 97 percent.

The No. 11 unit at the D.H. Mitchell Generating Station of Northern Indiana Public Service Company (NIPSCO) is currently the only utility operation in the U.S. and the only coal-fired application.

Initial startup of the NIPSCO Wellman-Lord absorber was on July 19, 1976. An extended shutdown period began on November 28, 1976, when high-pressure steam supply failures from the boiler and from emergency backup systems to the FGD plant resulted in freeze damage to the FGD plant. The shutdown lasted until early January 1977. During the period from July through November 1976, the Unit 11 boiler operated for 121 full days and 10 partial days, while the SO_2 removal system of the FGD plant operated for 71 full days and 23 partial days and was down for 38 days. The steam supply failures previously mentioned were responsible for 28 of the 38 days that the system was down.

During the three sustained operating periods, the absorber demonstrated the capability of greater SO_2 removal than specified in the performance criteria. The efficiencies are shown in Figures 4-29, 4-30, and 4-31.

The inlet flue gas contained as high as 2,800 ppm SO_2; the normal inlet SO_2 concentration, however, ranged from 2,100 to 2,300 ppm. Flue gas volume exceeded that expected. Outlet SO_2 concentrations normally ranged from 170 to 190 ppm, demonstrating the capability of SO_2 removal in excess of 90 percent.

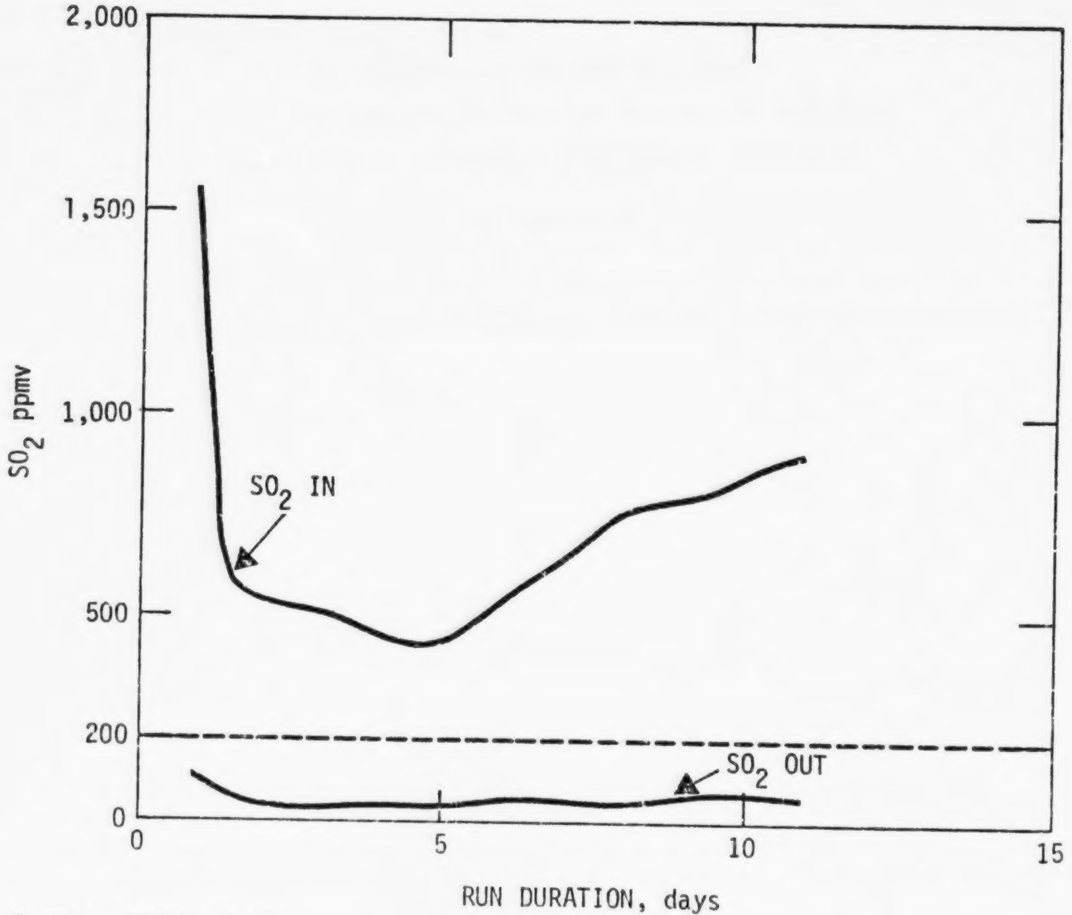


NOTE: THE SO_2 CONCENTRATION CURVES HAVE BEEN EXTRAPOLATED THROUGH DAYS 3 AND 5 BECAUSE OF INOPERATIVE INSTRUMENTATION

Source: PEDCo, 1977a.

FIGURE 4-29

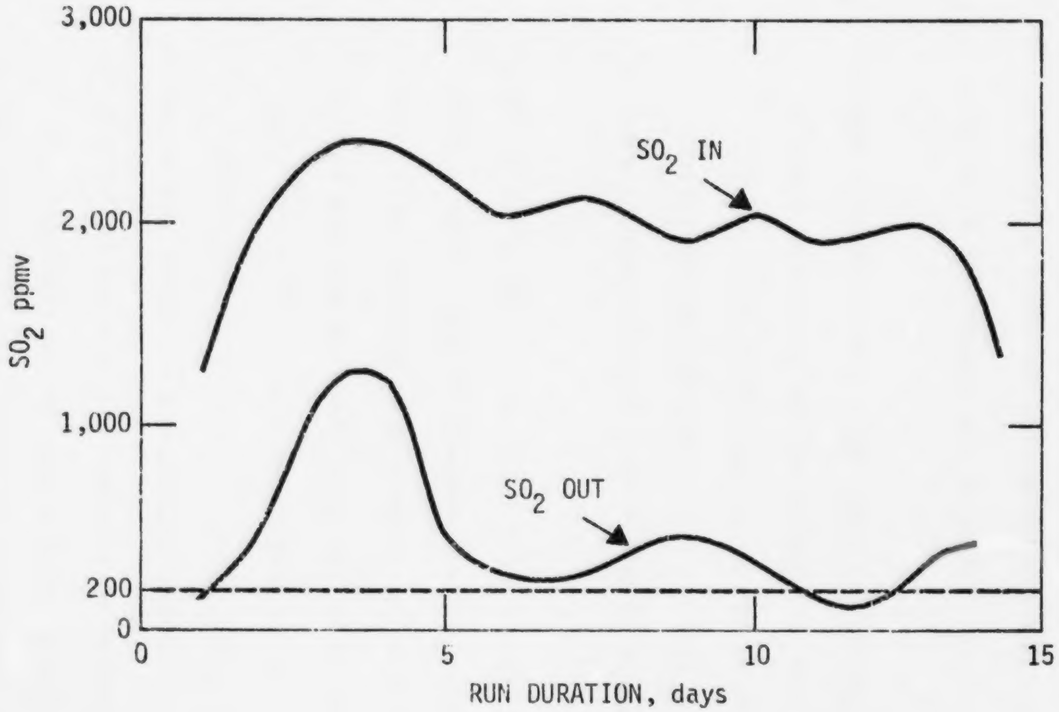
INLET AND OUTLET SO_2 CONCENTRATIONS DURING RUN NO. 1



Source: PEDCo, 1977a.

FIGURE 4-30

INLET AND OUTLET SO_2 CONCENTRATIONS
DURING RUN NO. 2



NOTE: THE POOR SO_2 RECOVERIES DURING THIS PERIOD RESULTED FROM POOR QUALITY SOLUTION CAUSED BY MECHANICAL PROBLEMS IN THE SODA ASH FEED SYSTEM AND EVAPORATION AREA, AND LOW FEED RATES TO THE ABSORBER WHILE BALANCING TANK INVENTORIES.

Source: PEDCo, 1977a.

FIGURE 4-31

INLET AND OUTLET SO_2 CONCENTRATIONS DURING RUN NO. 3

There is only operating data for one large U.S. utility Wellman-Lord system, but 17 systems are operating in Japan. As of mid-1976 all reported greater than 90 percent (some more than 98 percent) SO^2 removal efficiencies. The on-stream time for the absorption area has been about 98 percent. None of the systems are on coal-fired boilers.

4.4.3.6 Spray Dryer/Fabric Filter. This semidry process removes SO_2 in two stages utilizing an alkaline slurry in a spray dryer in conjunction with a fabric filter to collect the reacted alkali. Spent sorbent may be disposed of (lime-limestone) or regenerated (soda ash, etc.) by chemical reduction to produce by-product elemental sulfur.

Figure 4-32 shows a typical flow sheet for the two-stage process. Flue gas enters the dryer and flows downward through a finely atomized spray of scrubbing solution containing an alkaline surry, thereby removing a large fraction of the SO_2. The flue gas then leaves the spray dryer by particulate loaders and enters the second stage fabric filter where additional SO_2 is removed by reaction with unused sorbent; the fabric filter also serves to remove particulate matter. A summary evaluation of this process is given in Table 4-28.

The SO_2 removal efficiency varies with the sorbent used. Tests have shown that efficiencies are highest for sodium sulfite which, at stoichiometric ratios of 1.0 and 1.5, removes over 90 percent of the SO_2 (>80 percent in the spray dryer and another 10 percent in the fabric filter). Dry injection of sodium bicarbonate or nahcolite

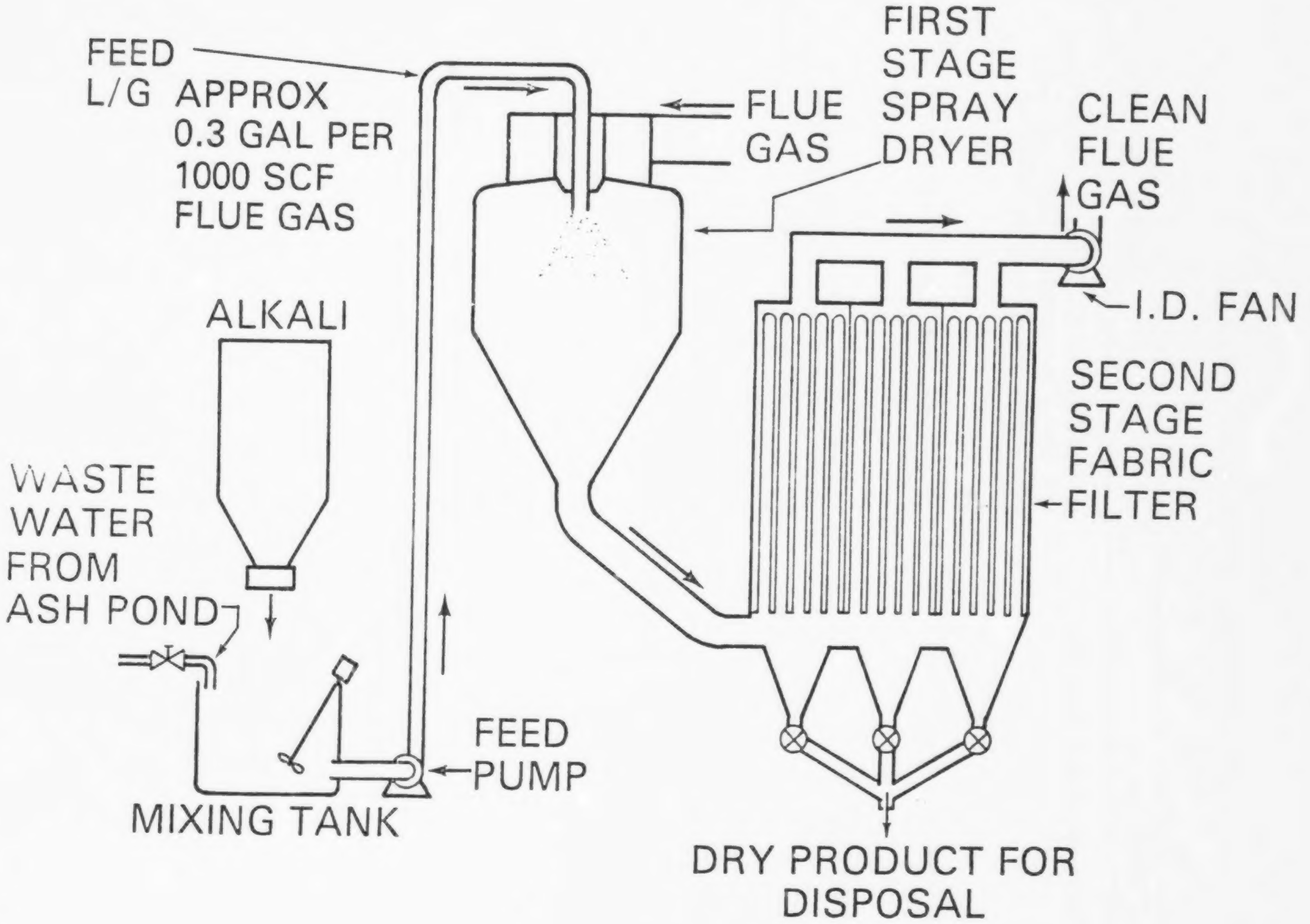

FEED
L/G APPROX
0.3 GAL PER
1000 SCF
FLUE GAS
FLUE
GAS
FIRST
STAGE
SPRAY
DRYER
CLEAN
FLUE
GAS
I.D. FAN
ALKALI
SECOND
STAGE
FABRIC
FILTER
WASTE
WATER
FROM
ASH POND
FEED
PUMP
MIXING TANK
DRY PRODUCT FOR
DISPOSAL

FIGURE 4-32

FLOW SHEET - TWO-STAGE DRY SCRUBBER/SO_2 ABSORBER

TABLE 4-28

SPRAY DRYER/FABRIC FILTER PROCESS EVALUATION

PARAMETER	COMMENTS
Process complexity, operability and reliability	Combines two technologies -- spray drying and fabric filtration -- which have had wide commercial application in other industries.
Process performance	SO_2 removal capability greater than 90 percent.
Wastes/products	Produces a dry powder mixture of sodium or calcium sulfite and sulfate, unreacted absorbent and flyash; potential regeneration product is sulfur.
Development status	Demonstration unit scheduled to be operational on 100 MW coal fired power plant by late 1979. (Eighteen are now under order.)
Advantages/disadvantages	Minimal process development required -- both technologies commercially available; wet scrubber not required; low liquid/gas ratio; expensive absorbent (if soda ash is used, not if limestone is used) and fabric filters; lower SO_2 removal efficiencies.

($NaHCO_3$), a one-stage fabric filter process gave 89 percent SO_2 removal using a stoichiometric ratio of 1.5. Lowest efficiency was obtained with lime (CaO), which showed only 75 percent removal (50 percent in the spray dryer and 25 percent in the fabric filter) at a stoichiometric ratio of 1.2; this is due to the comparatively low solubility and reactivity of CaO. Overall efficiencies for the three sorbents under identical test conditions (1.0 stoichiometric ratio; 1240 ppm SO_2) were: sodium carbonate, 92 percent; sodium bicarbonate, 74 percent; and lime, 71 percent.

If sorbent regeneration is used, the spent sorbent is reduced with a carbonaceous reducing agent (petroleum coke or coal) at 1800°F. This regenerates the sorbent and produces hydrogen sulfide which is then converted to elemental sulfur in a Claus plant.

A program is now underway to design, build, test and operate a demonstration 100-MW spray dryer using an electrostatic precipitator rather than a fabric filter for particulate removal. The system will use a sodium carbonate absorbing solution and will regenerate the spent sorbent with a solid carbon reducing agent to produce hydrogen sulfide that will be converted to by-product sulfur in a Claus plant. Test operations on this coal-fired unit are expected to begin in late 1979. The SO_2 removal efficiency is expected to exceed 90 percent, using the electrostatic precipitator for particulate control. It is estimated that fabric filtration could be used at no additional costand could improve both the SO_2 and particulate removal efficiencies.

4.4.4 FGD Wastes

A more stringent NSPS would result in either or both an increase in the amount of FGD wastes and/or FGD by-product. The waste producers from lime/limestone and double alkali systems are virtually identical (mixtures of FGD sludge and fly ash). Wastes from regenerable systems are primarily fly ash and purged liquid effluents.

The volume of waste from a typical nonregenerable scrubber system over a 30-year period is shown in Table 4-29 for 1,000-, 500-, and 25-MW plants burning various coals under the alternative standards. The wastes are in general proportional to size.

The chemical and physical characteristics of sludge vary based upon a number of factors including coal, sorbent, scrubber, scrubber operating parameters, and ash collection. The primary properties of the sludge affected by these factors are:

Constituents
pH
Leaching characteristics
Bulk density
Permeability
Compaction
Concentration
Total dissolved solids
Water retention
Compressive strength
Viscosity
Porosity.

Because of high concentrations of salts and total dissolved solids, the presence of trace elements, and in some cases extreme

TABLE 4-29

VOLUME OF SCRUBBER WASTES PRODUCED BY TYPICAL
NONREGENERABLE SYSTEMS OVER A 30-YEAR PERIOD[a] (Acre-Feet)

Plant Size, MW	Eastern Coal[b]				Western Coal[b]		
	NSPS Alternatives						
	1.2 lb SO_2 per 10^6 Btu[c]	90% SO_2 Removal[d]	0.5 lb SO_2 per 10^6 Btu[e]		1.2 lb SO_2 per 10^6 Btu[f]	90% SO_2 Removal[g]	0.5 lb SO_2 per 10^6 Btu[h]
			Sludge	Coal wash Tailings			
1000	14,030	14,920	NE		NE	NE	NE
500	7,260	7,720	4280	830	2930	3720	3480
25	405	430	240	45	NE	210	195

[a] 50-percent average operating load factor; limestone absorbent, 80% utilization; waste includes ash:

50 percent for coals with 3.5%S
60 percent for coals with 0.8%S

[b] Eastern coal: 3.5% S, 12,000 Btu/lb, 14% ash; Western coal: 0.8% S, 8000 Btu/lb, 6% ash.

[c] 80% SO_2 removal by scrubbing

[d] 0.6 lb $SO_2/10^6$ Btu

[e] 40% sulfur removal by coal washing, 85% SO_2 removal by scrubbing

[f] 40% SO_2 removal by scrubbing

[g] 0.2 lb $SO_2/10^6$ Btu

[h] 75% SO_2 removal by scrubbing

NE - not estimated

Source: Aerospace Corp., 1977.

values of pH and COD, care must be taken in the choice of disposal methods for untreated sludges. Secondly, because of its highly water-retentive property, the material requires special handling, conditioning or chemical treatment in its disposal to make the disposal site reclaimable. Regardless of the type of handling or treatment in disposal, consideration must be given to seepage to groundwater, runoff to streams, intrusion into irrigation systems, direct impact on vegetation, and impact on ocean life if disposed of at sea.

Various forms of disposal are available and a selection depends not only on cost but also on the following factors which are generally site-specific: characteristics of the waste, climate, geology, topography, hydrology, and disposal site availability and proximity. Possible types of disposal are: ponding on indigenous clay soil; ponding with a flexible liner or a liner of impervious soil; ponding with underdrainage; surface or deep mine disposal; ocean disposal; and chemical treatment with landfilling. There are specific cases where some of these methods are applicable, environmentally and structurally. Although the chemical treatment approach is universally applicable, it is not necessarily the best choice in all cases if a ponding or mine disposal approach is environmentally acceptable and less expensive. All disposal methods require monitoring and site management throughout the active life of the site, and special provisions such as covering the site with soil and the growth of vegetation to either prevent rewetting the material or to prevent runoff problems, as applicable.

Three major products can be produced from flue gas scrubbing: gypsum from nonregenerable systems; and sulfur and sulfuric acid which are direct by-products of regenerable systems. Economically, gypsum is not directly competitive; however, in consideration of credits for disposal under certain conditions, it can be shown to be a cost-effective commercial item. Sulfuric acid would have to compete in an industry that is currently capable of producing 30 percent over demand. Attempts are being made to develop other products from sulfur sludge such as fertilizer and building materials (Aerospace Corporation, 1977).

4.4.5 Status of Flue Gas Desulfurization Technology

Several aspects of flue gas desulfurization technology have been the subject of continuous investigations. Rapid progress has been made in expanding the data base needed to support the design of commercial devices to treat flue gases from coal-fired boilers. Through research, development and demonstration, information has been acquired on all aspects of flue gas desulfurization, including the basic chemistry of the various processes, the design and performance of equipment, and the selection of appropriate construction materials.

Table 4-30 summarizes the number and capacity of FGD systems on utility boilers in the U.S. as of August 1977. Of these systems, 29 were operational (8,914 MW), 28 were under construction (11,810), and 68 systems were planned (32,628 MW). This table omits 16 installations (8,592 MW) whose operators are considering FGD as well as other control systems (e.g., low sulfur coal). Some 12 to 15 boilers (6,000 MW) that are definitely planning to use FGD systems are excluded, because the information is not ready for public release. Not shown in the table are 16 systems (1,488 MW) that have been shut down for various reasons. Several of these were demonstration systems; others were based on first-generation technology.

Flue gas desulfurization systems have been applied to new boilers and as retrofits in existing installations. Appendix E specifies the types of FGD systems associated with coal fired boilers in the U.S. A summary list of these applications (by system type) is provided in Table 4-31. Boilers equipped with flue gas desulfurization devices vary in capacity from relatively small units of 100 megawatts or less to large new units in the 800- to 850-MW class. The sulfur content of the coal and lignite that is burned or scheduled to be burned in these units ranges from 1 percent or less to approximately 5 percent.

As shown in Table 4-31, lime and limestone slurry scrubbing are currently the predominant processes in flue gas desulfurization applied to coal-fired utility boilers in the U.S.

TABLE 4-30

BREAKDOWN OF FGD UNITS

Status of Units, August 1977	Number of Units	Capacity, Megawatts
Operational	29	8,914
Under construction	28	11,810
Planned:		
Contract awarded	23	11,880
Letter of intent	5	1,892
Requesting/evaluating bids	5	2,825
Considering only FGD systems	35	16,031
TOTAL	125	53,352

Source: PEDCo, 1977e.

TABLE 4-31

FGD APPLICATIONS TO COAL-FIRED BOILERS

Process	Number of Units	Capacity, Megawatts
Limestone scrubbing	41	18,003
Lime scrubbing	24	9,910
Lime/fly ash scrubbing	8	4,047
Lime/limestone scrubbing	2	20
Double alkali scrubbing	3	1,102
Sodium carbonate scrubbing	5	1,009
Magnesium oxide scrubbing	4	846
Wellman Lord/Allied Chemical	3	830
Wellman Lord	1	180
Aqueous carbonate scrubbing	1	100
Process not selected	28	14,675
Regenerative, not selected	3	1,650
Throwaway, not selected	2	980
	125	53,352

Source: PEDCo, 1977.

4.4.6 Vendor Capabilities

4.4.6.1 FGD System Supply and Demand. Based on the new coal-fired boilers now planned for construction and a projected growth rate of 5.56 percent per year, approximately 510,000 MW of coal-fired boiler capability will be built between 1978 and the year 2000. The ability of FGD manufacturers to meet this demand was evaluated in terms of the present and proposed alternative NSPS of 0.5 lb SO_2/10^6 Btu and 90 percent control. For the alternative NSPS, it was assumed that a new standard would result in the use of FGD's on all new power plants, and that the distribution of types of FGD processes would be the same as the distribution of systems already planned and shown on Table 4-32. Table 4-33 shows the demand for FGD based on the projected new coal-fired units.

TABLE 4-32

APPROXIMATE PROCESS DISTRIBUTION OF PLANNED
FGD SYSTEMS ON NEW COAL-FIRED UTILITY BOILERS

FGD Process	Percent Application to New Units
Nonregenerable	
Lime scrubbing	25
Lime/alkaline fly ash scrubbing	13
Limestone scrubbing	52
Double alkali	3
Sodium carbonate	2
Regenerable	
Sodium solution	3
Magnesium oxide	2

Source: PEDCo, 1977c.

TABLE 4-33

PROJECTED UTILIZATION OF FLUE GAS DESULFURIZATION ON NEW COAL-FIRED UNITS

Year	Total Projected Capacity Additions, Megawatts	Projected Utilization of FGD Under Present NSPS,[a] Megawatts	Total Projected Utilization of FGD Under a 0.5 lb $SO_2/10^6$ Btu or 90% Control Regulations[b]
1978	11,950	10,200	11,950
1979	13,100	8,300	13,100
1980	19,700	11,200	19,700
1981	15,500	9,300	15,500
1982	15,300	9,200	15,300
1983	17,200	10,300	17,200
1984	16,300	9,800	16,300
1985	19,500	11,700	19,500
1986	6,400	3,800	6,400
1987	6,000	3,600	6,000
1988	19,000	11,400	19,000
1989	21,000	12,600	21,000
1990	21,000	12,600	21,000
1991	24,000	14,400	24,000
1992	24,000	14,400	24,000
1993	29,000	17,400	29,000
1994	23,000	13,800	23,000
1995	28,000	16,800	28,000
1996	30,000	18,000	30,000
1997	32,000	19,200	32,000
1998	33,000	19,800	33,000
1999	35,000	21,000	35,000
2000	37,000	22,200	37,000

[a] Figures after 1980 reflect an assumed 60 percent utilization of FGD.
[b] Based on 100 percent utilization of FGD on new coal-fired boilers.

Source: PEDCo, 1977c.

Responses received from 13 out of 18 FGD systems manufacturers surveyed indicated they believe they will be capable of supplying the design personnel and equipment for the projected demand for FGD systems. The capability of the manufacturers to meet demand is flexible and increases in proportion to demand. Tables 4-34 and 4-35 give the comparison of supply versus demand for FGD systems under the current NSPS and two more stringent alternative levels--220 ng/J (0.5 lb $SO_2/10^6$ Btu) or 90 percent SO_2 reductions.

Ample limestone and to a lesser extent lime supplies exist in this country to supply all FGD systems. Shortages in specialized construction personnel are a possibility; however, the added personnel needs for new FGD systems are a very small portion of the total labor requirement. By about 1990, shortages in large scrubber modules and fans are also predicted by several of the suppliers depending on the sizes required at that time (PEDCo, 1977).

4.4.6.2 Construction Time and Guarantees. Table 4-36 gives the design, construction and startup time requirements for an FGD process based on the estimates of 13 FGD process manufacturers. Table 4-37 lists the items from the manufacturer's experience that can delay installations as a result of long lead times. A typical construction schedule for a 500 MW unit with and without FGD is shown in Appendix F. The schedules exclude the preliminary study which is estimated at 18 to 24 months.

TABLE 4-34

COMPARISON OF SUPPLY VERSUS DEMAND FOR FGD SYSTEMS ON NEW COAL-FIRED UTILITY BOILERS UNDER PRESENT NSPS

Time period	FGD Vendor Capability with Present Staff, Megawatts	Projected Demand, Megawatts	Differential Capacity, Megawatts
1978-1982	205,710	48,200	+157,510
1983-1987	212,885	39,200	+173,685
1988-1992	218,540	65,400	+153,140
TOTAL	637,135	152,800	484,335

Source: PEDCo, 1977c.

TABLE 4-35

COMPARISON OF SUPPLY VERSUS DEMAND FOR FGD SYSTEMS ON COAL-FIRED UTILITY BOILERS UNDER MORE STRINGENT NSPS

Time Period	FGD Manufacturers' Capability with Present Staff, Megawatts	Projected Demand, Megawatts	Differential Capacity, Megawatts
1978-1982	371,500	75,550	+295,950
1983-1987	421,890	65,400	+356,490
1988-1992	434,990	109,000	+325,990
TOTAL	1,228,380	249,950	978,430

Source: PEDCo, 1977c.

TABLE 4-36

TIME REQUIRED FOR FGD SYSTEM DESIGN, INSTALLATION, AND STARTUP[a]

Size, Megawatts	Time Required for Design and Installation		Time Required for Startup[b]	
	Average Months	Range Months	Average Months	Range Months
<100	22.2	6 - 36	1.8	0.5 months to 6 months
100-400	24.4	8 - 36	2.3	0.5 months to 6 months
400-800	30.1	18 - 42	2.4	0.5 months to 7 months
>800	33.1	20 - 42	2.7	0.5 months to 7 months

[a] Represents the responses of 12 manufacturers.

[b] Startup is defined as the time between completion of plant construction and when the plant can operate at an acceptable level of capacity.

Source: PEDCo, 1977c.

TABLE 4-37

LEAD TIME AND DELAY FREQUENCY OF
VARIOUS ITEMS IN THE DESIGN AND INSTALLATION OF AN FGD SYSTEM

Item	Average lead time,[a] months	Number of manufacturers replying[b]				
		Critical path item		Delay frequency		
		Yes	No	High	Average	Low
Process design	2.6	8	2	1	4	5
Detailed engineering design	8.6	9	1	1	6	3
Equipment fabrication						
• Structural steel	6.0	4	6	0	6	4
• Scrubber vessel/tanks	7.6	7	3	2	4	4
• Fans	11.4	10	0	2	6	2
• Pumps	9.4	3	7	2	5	3
• Instrumentation	8.3	2	8	4	3	3
• Motors	8.0	4	6	2	4	4
• Piping	7.2	7	3	0	9	1
Equipment installation	12.5	9	1	5	4	1
Reactant procurement (e.g., limestone)	2.0	1	9	0	5	5

[a] Responses of 9 manufacturers.

[b] Responses of 10 manufacturers.

Source: PEDCo, 1977c.

As noted in Appendix F an FGD system can be constructed with minimal impact on the overall construction schedule of the power plant. The increase in construction time is 6 months for a 3-year schedule. However, an increase in construction personnel can eliminate this increase in construction time. While the elapsed time needed to construct a plant is a function of manhours, the actual number of men that can be used during any one stage of erection is limited.

The survey of manufacturers also indicated that generally, they are willing to guarantee 90 percent SO_2 removal and some are prepared to guarantee better than 90 percent SO_2 removal, on a case-by-case basis. Table 4-38 summarizes the terms of guarantees.

Seven out of 12 FGD manufacturers surveyed will guarantee performance (availability of 90 percent) of the FGD systems they market. Vendors of the double alkali system have enough confidence in their systems to offer a 90 percent availability for the first year of operation and 100 percent for the life of the plant (based on a boiler operating rate of 70 percent for some of the new full-scale utility applications) and these systems are for 85 to 95 percent SO_2 removal of high sulfur coal (PEDCo, 1977).

All responding manufacturers would guarantee the costs of the FGD system:

- Four manufacturers would guarantee cost subject to an escalation clause

TABLE 4-38

GUARANTEES OFFERED BY MANUFACTURERS FOR SO_2 REMOVAL[a]

Company[b]	Level of SO_2 removal guaranteed		
	<90%	90%	>90%
A		Minimum guarantee given.	Is willing to offer 95% guarantee on case-by-case basis.
B		Minimum guarantee give.	Guarantee of >90% is based on inlet SO_2 concentration.
C			Would guarantee 95% in all cases.
D			Have guaranteed up to 92% in the past. Currently case-by-case.
E			Have guaranteed >90% in the past.
F		This guarantee is normally given.	Depending upon the process, they would guarantee >90%.
G		This guarantee is given where SO_2 inlet concentration is 500 to 4000 ppm.	Have guaranteed up to 95% in the past.
H	Would normally guarantee 80 to 85%.	This guarantee is given where low-sulfur coal is utilized.	
I		Minimum guarantee given.	Are prepared to offer better than 90% when either low- or high-sulfur coal is burned, but would not guarantee less than 50 ppm SO_2 concentration in exit stream.
J		This guarantee is usually given when coal with 3 to 4% sulfur is burned.	
K		This guarantee is normally given when either low- or high-sulfur coal is burned.	In many cases they guarantee 95% when high-sulfur coal is burned.
L		Minimum guarantee given.	May guarantee up to 95% on a case-by-case basis.

[a] Represents the responses of 12 manufacturers.

[b] Company names are deliberately withheld.

Source: PEDCo., 1977c.

- One manufacturer would negotiate the terms of the guarantee
- None of the other manufacturers specified provisions.

Eight of the 12 manufacturers responding stated they would offer operation and maintenance service. They further indicated that they would issue a guarantee but did not specify the provisions.

4.4.7 Availability

System operating performance is discussed separately for each FGD system description in Appendix D. This section describes operating availability of FGD systems in general.

Four parameters are commonly used in reporting FGD system operating data:

1. $\text{Availability} = \dfrac{\text{hours the FGD system was available for operation}}{\text{hours in the period}}$

2. $\text{Reliability} = \dfrac{\text{hours the FGD system was operated}}{\text{hours the system was required to operate}}$

3. $\text{Operability} = \dfrac{\text{hours the FGD system was operated}}{\text{hours the boiler was operated}}$

4. $\text{Utilization} = \dfrac{\text{hours the FGD system was operated}}{\text{hours in the period}}$

To develop availability data that would be pertinent to the utility industry, the following criteria were used:

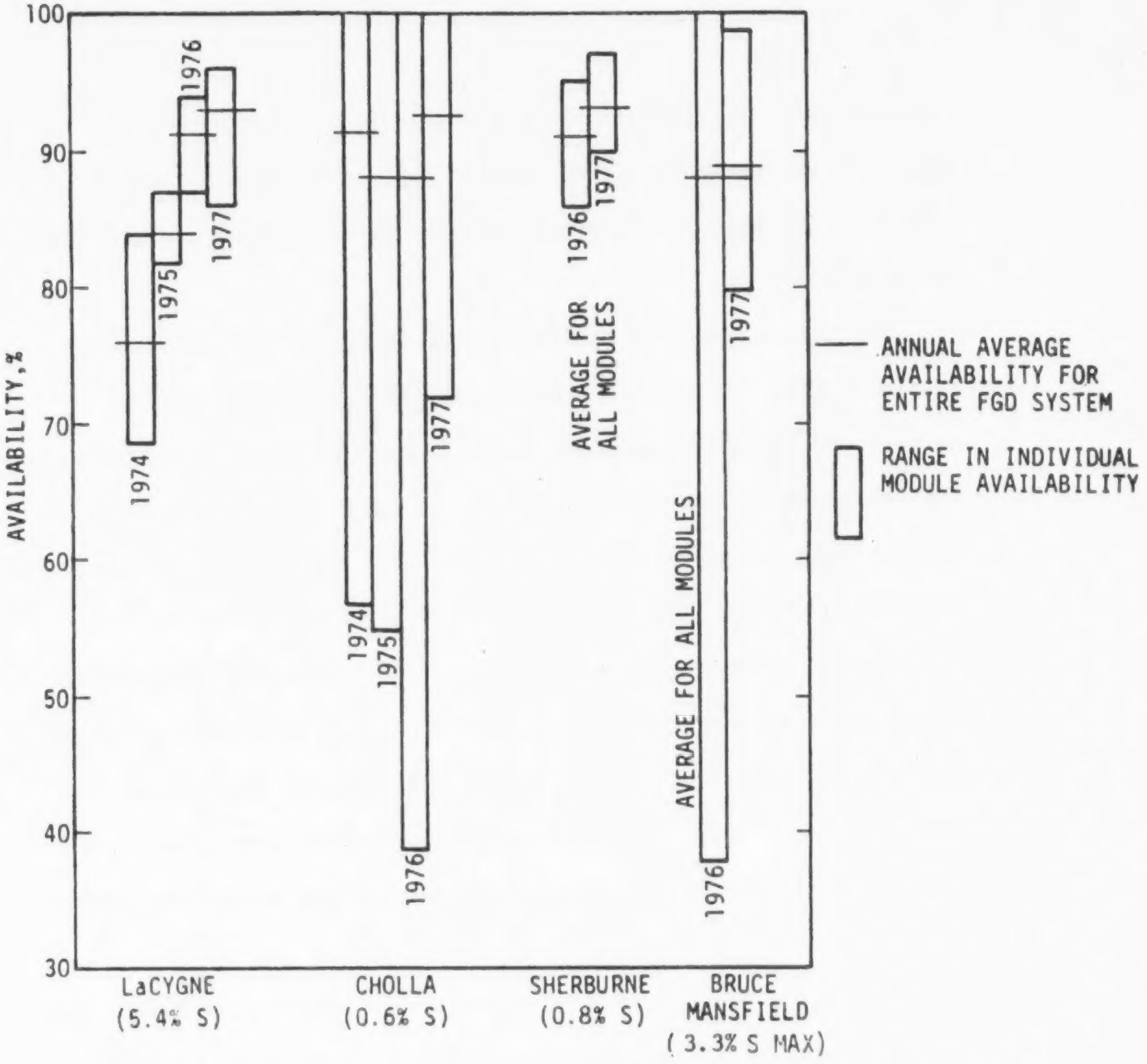
1. The FGD system must treat flue gas from a utility generating station greater than 50 MW.
2. The system has been operating for 1 or more years
3. The system is not a demonstration or test unit

Unfortunately, availability data for plants fitting these criteria were only available for seven systems, all of which are lime or limestone systems. Performance data for these systems are presented in Table 4-39.

The average modular availabilities showed a wide range among systems. Five systems did show availabilities greater than 70 percent and three were greater than 88 percent. Four of the units in the table had utilization factors of approximately 50 percent or greater indicating the load in the FGD units has been large enough to quantify operating history.

Figure 4-33 gives more comprehensive availability data on four of the seven systems. While individual modular availability varied over a wide range, the annual average availability for all the FGD system was generally well over 80 percent. Furthermore, for 1977, three of the four systems operated at better than 90 percent availability.

FGD system availability is dependent on both system design and the manner in which the system is operated. There is a trend in overall system availability, as a function of the year the system was started up. Continuing improvement in availability is evident as the newer, improved units come on line. Although some recent installations have not shown particularly high availability, a statistically significant correlation does exist between startup date and average availability. In addition, only one of these newer stations had a



Source: PEDCo, 1977d.

FIGURE 4-33

AVERAGE AVAILABILITY FOR SELECTED FGD SYSTEMS

TABLE 4-39

FGD SYSTEM PERFORMANCE DATA--AVERAGE VALUES[a]

System	Size, MW[b]	Fuel (%Sulfur)	Startup Date	Average Modular Availability		Utilization	
				Operating Date	Percent	Operating Date	Percent
Will County No. 1	167	4.0	2/72	3/75-1/77	44.2	3/77-1/77	33.6
La Cygen No. 1	820	5.0	2/73	1/74-3/77	88.6	N. R.[c]	N. A.[d]
Phillips	410	1-2.8	7/73	8/73-10/75	60.6	8/73-10/76	49.7
Cholla No. 1	115	0.44-1	10/73	12/73-5/75	91.5	N. R.	N. A.
Green River	64	3.8-4	9/75	12/75-3/77	72.6[e]	12/75-3/77	62.1
Sherburne County No. 1	710	0.8	3/76	5/76-8/77	90.9	5/76-3/77	70.9
Bruce Mansfield No. 1	825	4.5-5.0	4/76	5/76-8/77	77.8[f]	5/76-12.76	76.8

[a] Radian Corporation, 1977a.
[b] PEDCo, 1977d.
[c] Not reported.
[d] Not applicable.
[e] Includes 2 month outage in March-April 1977 to reline stack.
[f] Includes reduction to half-load from March-July 1977 due to repairs to stack lining.

spare module available for use in the event of malfunction of the operating modules. A spare scrubbing module has a significant effect on overall system availability, since it can replace a module that may be shut down for any reason.

It should be emphasized that the major portion of the performance data is based on lime and limestone systems, and many second generation FGD systems as well as newer lime/limestone systems, are expected to have greater availability. This concept is reenforced by an increase on the part of manufacturers to guarantee performance (both availability and removal efficiency) and some commitment for sparing of scrubber modules. In any case, based on current operating data, it should be possible for FGD systems to achieve near 90 percent or better availability irrespective of fuel sulfur content.

Various measures have been and can be used to improve on maintaining high FGD availability. Such items as separate maintenance crews for the FGD, a dedication to operation, frequent cleaning and inspection, and use of a successfully demonstrated design concept can have a significant effect on FGD performance. Measures to improve FGD availability can be categorized in terms of three areas: maintenance methods, operating techniques and design concepts.

5.0 DESCRIPTION OF THE EXISTING ENVIRONMENT

This section describes the industries that would be affected by the proposed revision to the NSPS, and the air, water, land, and energy conditions which relate to the NSPS prior to the revision.

5.1 The Electric Power Industry in the United States

The electric power industry is made up of many utility systems that vary greatly in size, type of ownership and functions. The industry is made up of investor-owned companies, non-Federal public agencies, Federal agencies and cooperatives. The investor-owned or private sector is by far the largest, accounting for 77 percent of the 1.9 billion kWh of electrical energy generated in 1974 (U.S. Federal Power Commission, 1976). Nearly all of the approximately 200 major investor-owned utilities operate integrated generation, transmission and distribution systems.

Five Federal agencies* market electrical power generated at facilities owned and operated by the Federal Government. The Tennessee Valley Authority is the largest Federal electric system as well as being the largest electric system in the nation. Electrical energy marketed by the Department of the Interior is generated hydroelectrically and, together with the energy generated by the Tennessee Valley Authority, represents approximately 12 percent of the total energy generated in the U.S. Public non-Federal electric systems, including the systems of towns and cities, a few counties, special utility districts and various state authorities, generate 9 percent of the total production. Electric cooperative systems supply power in many of the rural areas of the country and account for 2 percent of the total production of electric energy.

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*The Tennessee Valley Authority, Bonneville Power Administration, Southwestern Power Administration, Southeastern Power Administration and the Bureau of Reclamation. The Secretary of the Interior is the marketing agent for power produced by all Federal power projects except that produced by the Tennessee Valley Authority.

5.1.1 Generating Capacity

The total electrical generating capacity presently installed in the U.S. is 545,364 MW (U.S. Federal Energy Administration, 1977). Coal-fired steam turbine generators make up 38 percent of the total capacity; oil-fired units 25 percent; gas-fired units 14 percent; hydroelectric units 12 percent; nuclear units 9 percent and other units, including units of unrecorded types, 3 percent.

Assuming no revision of the present NSPS, long range forecasts of future additions to generating capacity have been developed as part of a study (Teknekron, 1978a) sponsored by the U.S. Environmental Protection Agency. According to these forecasts, the distribution of capacity additions by energy source, or the mix of additions, will be sensitive to the rate of growth in installed capacity that will be required to meet increasing demand for electrical energy. If a moderate rate of growth is experienced between 1977 and 1995, nuclear units will constitute 59 percent of total additions and coal-fired units 36 percent. In a high growth scenario the corresponding figures are 45 percent for nuclear units and 47 percent for coal units. Installed capacity in the U.S. by 1995 would reach 1,081.5 GW (35 percent nuclear, 37 percent coal) with moderate growth and 1,311.7 GW (31 percent nuclear, 44 percent coal) with high growth. These scenarios underlie the analysis of impacts presented in later sections of this report. A description of the scenarios and derivation of the above forecasts is given in Appendix J.

5.1.2 Production of Electrical Energy

The total net production of electrical energy in the U.S. reached 2,036.5 billion kWh in 1976 (U.S. Federal Power Commission, 1977). Approximately 46.3 percent of the energy was derived from coal, 12.7 percent from oil, 14.5 percent from gas, 9.4 percent from nuclear fuel and 0.2 percent from other sources. During this year, the electric utility industry consumed more than 448.1 million tons* of coal (U.S. Federal Power Commission, 1977).

Current projections (U.S. Federal Power Commission, 1977b; Edison Electric Institute, 1977) indicate that coal will continue to supply 47 to 48 percent of the primary energy from 1977 to 1986. On the basis of data pertaining to 1975, the U.S. Federal Power Commission (1977b) estimates that 111,600 MW of new coal-fired generating capacity will be brought on line by the utility industry between 1976 and 1985 (U.S. Federal Power Commission, 1977). Electrical energy derived from coal would amount to 1,227 billion kWh in 1980 and 1,690 billion kWh in 1985. Later projections based on actual data for 1976

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*One ton = 0.9842 metric tons.

(Edison Electric Institute, 1977) are in substantial agreement with the forecasts of the Federal Power Commission. For example, the amount of electrical energy that will be derived from coal, according to these later projections, is predicted to be 1,230 billion kWh in 1980 and 1,595 billion kWh in 1985 (Edison Electric Institute, 1977).

5.1.3 Supply of Coal

Short range forecasts based on the present NSPS indicate that consumption of coal by the electric utility industry will increase from the level of 406 million tons* in 1975 and reach 570 million tons in 1980 and 770 million tons in 1985 (U.S. Federal Power Commission, 1977). Historical patterns of coal demand and supply are expected to change over the decade. Departures from these patterns have occurred for several reasons, among which is the promulgation in 1971 of the existing NSPS SO_2 emissions for coal-fired steam generators (U.S. Federal Power Commission, 1977). The present standard has accelerated the procurement of low-sulfur coal to fuel the generating units required to comply with the standards. Included in this category is the major portion of coal-fired additions scheduled to become operational on or before 1985, although some of the later units could become subject to the revised standard. Other factors expected to increase U.S. reliance on coal over the next several years include the anticipated substitution of coal for oil under the provisions of the Energy Supply and Environmental Coordination

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*One ton = 0.9842 metric tons.

Act of 1974 and the phase out of natural gas in areas where it is now a primary source of energy (U.S. Federal Power Commission, 1977).

The increased demand for low-sulfur coal to supply new coal-fired units is expected to affect primarily the development of coal resources in western states. It is anticipated that more than 55 percent of the demand created by new coal-fired units coming on line between 1976 and 1985 will be supplied by coal originating in the western states of Arizona, Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah and Wyoming (U.S. Federal Power Commission, 1977). As a consequence, projections indicate coal from these states will supply approximately 35 percent of the total coal needs of the electric utility industry, increasing from a level of 16.9 percent in 1975. A high rate of growth in the production of steam coal is expected to prevail in the Western Midwest Region (Bureau of Mines Districts 12, 14, and 15). Approximately 15 percent of the demand created by new coal-fired units is expected to be met from resources in this region, raising its share of the total production of steam coal from 3.9 percent in 1975 to 10 percent in 1985. The supply of coal from other coal-producing regions is expected to increase over the same years, although the relative share of the overall production of steam coal originating in each of these regions is expected to decline (U.S. Federal Power Commission, 1977).

Requirements for coal to fuel new units scheduled for service between 1976 and 1985 are expected to vary markedly throughout the country. Details of the projected demand attributable to new units in the various regions of the country are given in Table 5-1. As the data indicate, the largest incremental demands will be in the West South Central and West North Central states. The rate of growth is expected to remain high throughout the decade in the West South Central states, whereas a moderation in the rate of growth is expected to prevail in the West North Central states in the earlier part of the period. Rapid growth in demand between 1980 and 1985 is expected in the South Atlantic and East South Central states.

5.1.4 Origin and Destination of Coal for New Units

The Appalachian Region has been the traditional major source of coal for the nation's electric utility industry. For reasons cited previously, new supply patterns are forming in the case of coal for generating units scheduled to become operational between 1976 and 1985. A relatively small fraction, 14.5 percent, of the quantity of coal needed to fuel these units is projected to be of Appalachian origin (U.S. Federal Power Commission, 1977). Based on the existing NSPS, the region would remain as the largest source of steam coal in 1985, but its share of the total supply would decrease from 44.8 percent in 1975 to an estimated 35 percent in 1985. The entire incremental production of coal from Appalachia would be consumed by new units in the East.

New units in the West will depend almost entirely on bituminous and subbituminous coal and lignite produced in states west of the

TABLE 5-1
INCREMENTAL COAL DEMAND IN 1980 AND 1985 ATTRIBUTED TO NEW UNITS SCHEDULED FOR OPERATION BETWEEN 1978 AND 1985

REGIONS/STATES	INCREMENTAL COAL DEMAND IN THOUSANDS OF TONS	
	1980	1985
New England (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont)	0	0
Mid Atlantic (New York, Pennsylvania, New Jersey)	10,300	18,100
East North Central (Illinois, Indiana, Michigan, Ohio, Wisconsin)	24,214	47,004
West North Central (Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota)	40,025	67,330
South Atlantic (Delaware, Florida, Georgia, Maryland, North Carolina, South Carolina, West Virginia, District of Columbia, Virginia)	6,711	23,792
East South Central (Alabama, Kentucky, Mississippi, Tennessee)	9,076	23,249
West South Central (Arkansas, Louisiana, Oklahoma, Texas)	57,113	124,207
Mountain (Arizona, Colorado, Idaho, Montana, Nevada, Utah, Wyoming)	26,085	52,889
Pacific (Oregon, California, Washington)	400	1,200
TOTAL	173,924	357,771

Source: U.S. Federal Power Commission, 1977.

Mississippi River if the NSPS for coal-fired utility boilers remains at 520 ng/J (1.2 lb $SO_2/10^6$ Btu). These units represent the largest incremental demand for coal for two reasons: the large fraction (58.8 percent) of new coal-fired capacity scheduled to be installed in the western states, and the lower average heat content of western coal. An estimated 68.7 percent of the total incremental production of coal will be required in these states with the remainder (31.3 percent) crossing the Mississippi River to eastern destinations.

Details of the projected origin and destinations of coal to supply new units in 1980 and 1985 are given in Table 5-2 and graphical displays of coal movements in these years are shown in Figure 5-1 and 5-2. The importance of the western regions of the Northern Great Plains is underscored by the information presented in Figure 5-1. As indicated, most of the incremental coal production in the region will be delivered to adjacent areas of the country, particularly to the West North Central and the West South Central regions. This region will supply 141 million tons of coal annually, or 39.4 percent of the overall incremental demand by 1985, with relatively small quantities of coal reaching as far as the South Atlantic Region (U.S. Federal Power Commission, 1977).

Figure 5-2 shows that the incremental production of coal in all of the other coal-producing regions will be used primarily to satisfy the demand generated by new units within the region (U.S. Federal Power Commission, 1977). Coal from the four states in the Mountain

TABLE 5-2
PROJECTED MOVEMENT OF COAL FOR NEW UNITS SCHEDULED TO BECOME OPERATIONAL BETWEEN 1976 AND 1985

REGION OF ORIGIN	STATE OF DESTINATION	DEMAND IN 1,000 TONS	
		1980	1985
East	Alabama	1,980	6,398
	Florida	0	651
	Delaware	800	800
	Georgia	317	6,517
	Kentucky	1,800	6,275
	Ohio	4,250	10,000
	Michigan	1,650	2,230
	Massachusetts	506	1,272
	North Carolina	1,410	4,464
	Pennsylvania	10,300	12,200
	South Carolina	463	1,407
		23,476	52,214
Eastern Midwest	Florida	987	987
	Georgia	1,234	1,234
	Illinois	2,485	6,490
	Indiana	6,640	11,700
	Iowa	20	270
	Kentucky	3,010	7,524
	Michigan	0	420
	Missouri	4,800	4,500
	Oklahoma	4,046	3,001
		23,222	36,358
Western Midwest[a]	Iowa	20	20
	Missouri	350	1,250
	Oklahoma	0	900
	Texas	21,419	51,845
		21,789	53,655
West	Arizona	5,885	5,885
	Arkansas	7,260	12,960
	Colorado	5,415	5,905
	Georgia	0	1,000
	Idaho	0	1,600
	Indiana	3,700	3,700
	Iowa	5,081	7,731
	Kentucky	6,093	11,690
	Louisiana	2,500	6,000
	Michigan	1,099	5,499

TABLE 5-2 (Concluded)

REGION OF ORIGIN	STATE OF DESTINATION	DEMAND IN 1,000 TONS	
		1980	1985
West (Continued)	Minnesota	5,500	9,400
	Massachusetts	1,780	1,780
	Montana	2,000	7,000
	Nebraska	4,411	6,770
	Nevada	365	8,746
	North Dakota	8,700	18,100
	New Mexico	3,220	5,450
	Oklahoma	6,000	7,303
	Oregon	400	1,200
	Texas	14,888	38,849
	Utah	2,400	5,238
	Wisconsin	3,730	6,470
	Wyoming	4,600	7,100
		91,077	197,684
Unknown	Arizona	2,200	2,200
	Colorado	0	1,730
	Florida	0	2,000
	Illinois	660	345
	Missouri	0	1,500
	New Mexico	0	1,035
	New York	0	5,900
	Ohio	0	150
	West Virginia	1,500	3,000
		4,360	17,860
TOTAL U.S.		173,924	357,771

[a] No shipments anticipated from Arkansas, Iowa, or the Oklahoma counties of Haskell, LeFlore and Sequoyah.

Source: U.S. Federal Power Commission, 1977.

FIGURE 5-1

FLOW OF COAL TO NEW GENERATING UNITS FROM THE WESTERN REGIONS OF THE NORTHERN GREAT PLAINS (IN 1000 TONS)

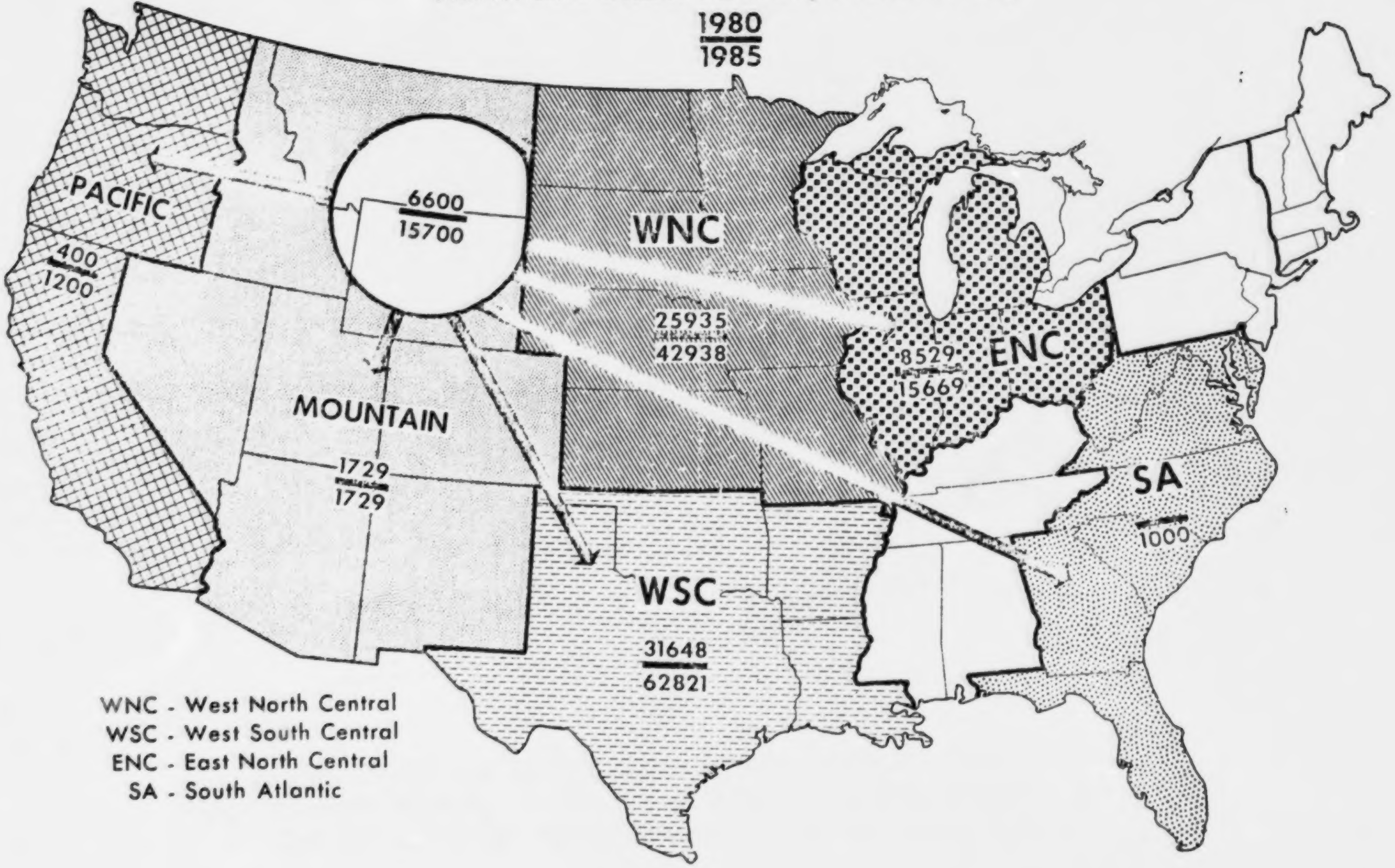
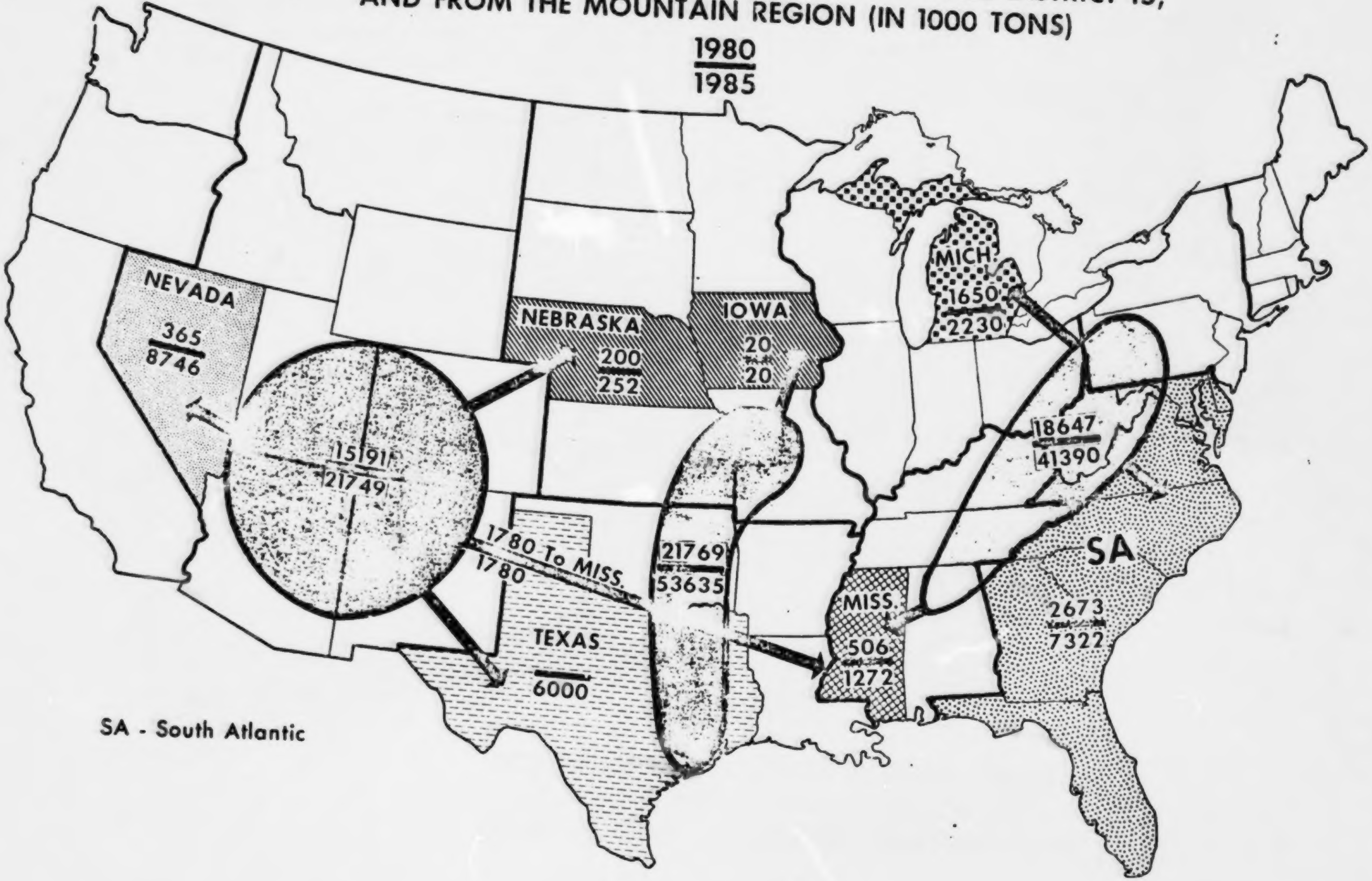

1980
1985
PACIFIC
400
1200
6600
15700
MOUNTAIN
1729
1729
WNC
25935
42938
ENC
8529
15669
SA
1000
WSC
31648
62821
WNC - West North Central
WSC - West South Central
ENC - East North Central
SA - South Atlantic

FIGURE 5-2

FLOW OF COAL TO NEW GENERATING UNITS FROM THE APPALACHIAN REGION, FROM U.S. BUREAU OF MINES DISTRICT 15, AND FROM THE MOUNTAIN REGION (IN 1000 TONS)

1980
1985


NEVADA
365
8746
15191
21749
NEBRASKA
200
252
IOWA
20
20
1780 To MISS.
1780
TEXAS
6000
21769
53635
MICH.
1650
2230
18647
41390
MISS.
506
1272
SA
2673
7322

SA - South Atlantic

Region--Arizona, Colorado, New Mexico and Utah--will supply 10.8 percent of the coal requirements for new units by 1985. Most of this coal will remain within the area, where many of the new units will be located close to producing mines. The demand for coal from the western Midwest (Bureau of Mines District 15, including Kansas, Missouri, Texas and part of Oklahoma) is projected to increase rapidly. Coal from this region will supply 15 percent of coal demand for all new units by 1985; and 96 percent of the incremental production in this area will be consumed in the state of Texas. As mentioned previously, 14.5 percent of incremental demand will be met by Appalachian coal, with deliveries remaining within the eastern region.

5.1.5 Long-Range Projections

Long-range projections based on the existing standard indicate that growth in national coal production beyond 1985 will depend strongly on the demand for coal generated by the electric utility sector (ICF, Inc., 1978). In a scenario of moderate growth in demand for electrical energy (5.8 percent annually through 1985 and 3.4 percent beyond 1985), consumption of coal by utilities is forecast to reach 1 billion tons per year by 1995. In a high growth scenario (5.8 percent annually through 1985 and 5.5 percent beyond 1985) the corresponding projection would be 1.4 billion tons. Pertinent details of predicted national coal production are shown in Table 5-3.

TABLE 5-3

PREDICTED NATIONAL COAL PRODUCTION

Scenario	National Coal Production (Millions of Tons)			
	1975	1985	1990	1995
Moderate Growth				
Nonutility coal	223	416	611	763
Utility coal	424	802	973	1000
Total production	647	1218	1584	1763
High Growth				
Nonutility coal	223	416	611	763
Utility coal	424	802	1157	1438
Total production	647	1218	1768	2201

Source: ICF, Inc., 1978.

Regional production forecasts indicate that the greater part of incremental production through 1995 will be in the West, especially in the Northern Great Plains. The substantial growth in the West is attributed to the: (1) vast resources of coal that can be produced at low prices, (2) availability of coal that can be burned without FGD while meeting existing standards, (3) projected growth in consumption within the western region, and (4) shipment of coal across the Mississippi River.

Western coal consumed in the east is forecast to be primarily subbituminous low-sulfur coal from Montana and Wyoming and, to a lesser degree, bituminous coal from Colorado. Predictions show that these coals will be consumed mostly by the utility sector in the states east of the Mississippi River but west of the Appalachian Mountains. The increase in shipments is attributed to new power plants that would be required to meet the existing standard and older plants switching to low sulfur western coals in response to state implementation plans. It is predicted that Appalachian production will remain fairly level because resources of low-sulfur coal in the region, particularly in Central Appalachia, are limited and expensive to exploit; and low sulfur coals produced in this region are generally used for metallurgical purposes. The growth in production of Northern Appalachian high-sulfur coal is expected to be modest because of the limited increase in demand for this coal generated by growth in the utility sector and the large increase in nuclear capacity in the geographic markets of Northern Appalachia coal. Growth in coal production in the Midwest is predicted because coal from this area, although high in sulfur content, can be mined and transported to many large markets at competitive prices. Details of projected regional coal production in a high growth scenario are presented in Table 5-4.

TABLE 5-4

REGIONAL COAL PRODUCTION IN HIGH GROWTH SCENARIO

Region	Regional Coal Production (Millions of Tons)			
	1975	1985	1990	1995
Northern Appalachia	179	172	205	223
Central and Southern Appalachia	218	236	237	241
Midwest and Central West	151	243	298	331
Northern Great Plains	55	424	810	1160
Rest of West	44	143	218	247
National Total	647	1218	1768	2201
Western Coal Consumed in East	21	206	455	601

Source: ICF, Inc., 1978.

5.2 Coal Resources of the United States

The vast resources of coal in the U.S. have been identified by the U.S. Geological Survey. Deposits at depths of less than 3,000 feet contain about 1,700 billion tons (U.S. Department of the Interior, Bureau of Mines, 1977). Based on geological knowledge and theory it is thought that an additional coal resource of even larger size exists. Estimates of the quantities of coal in relatively thick beds and formations that are amenable to mining by conventional surface and underground methods have been developed by the U.S. Department of the Interior, Bureau of Mines. From information available on January 1, 1976, the Bureau estimates that the demonstrated reserve base* of coal in the U.S. is 438 billion short tons.

The reserve base refers to coal that is technically and economically minable under present conditions. It is not a fixed quantity, but one that increases with discovery and additional development, decreases with mining, and changes as the criteria underlying the estimate of its extent are modified.** No consideration is given to factors affecting the marketability of specific coals in computing the reserve base. Nevertheless, the criteria applicable to bed thickness and depth generally correspond to the characteristics of deposits presently being mined.

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*The reserve base is composed of all coals in deposits that meet certain criteria related to the thickness and depths of the deposits. Criteria applicable to thickness are: 28 inches or more for bituminous coal and anthracite, 60 inches or more for subbituminous coal and lignite. Deposits of all ranks at depths greater than 3,000 feet from the surface are excluded from the reserve base, and only the lignite beds that can be mined by surface methods are included. These beds occur generally at depths no greater than 200 feet. Certain coal beds that do not meet the depth and thickness criteria are included in the reserve base because they are presently being mined or could be mined commercially at this time. The term "demonstrated" denotes both measured and indicated categories as defined by the Geological Survey and the Bureau of Mines. Coal deposits are included in these categories where, on the basis of geological projections and engineering evaluation, there is a high degree of certainty regarding their existence (U.S. Department of the Interior, Bureau of Mines, 1977).

**The current estimate of 438 billion tons of coal as the reserve base represents an increase of 1.5 billion tons over the estimate derived previously from information available on January 1, 1974 (U.S. Department of the Interior, Bureau of Mines, 1975).

5.2.1 Geographical Distribution of Coal Deposits

The reserve base of 438 billion tons of coal is distributed widely throughout the U.S. with 46 percent of the base found in states east of the Mississippi River, and 54 percent in western states and Alaska (U.S. Department of the Interior, Bureau of Mines, 1977). Quantities of coal of different rank as well as quantities amenable to production by underground and surface mining methods differ markedly in the various coal rich areas of the country. An evaluation of coal deposits by rank shows that 52 percent of the total reserve base is composed of bituminous coal, 38 percent subbituminous coal, 8 percent lignite, and 2 percent anthracite. Approximately 85 percent of the bituminous coal and virtually all of the anthracite are found east of the Mississippi River. Most of the subbituminous coal and lignite is found in the West.

One-third of the reserve base (141 billion tons) is in beds so close to the surface or in beds so thick that underground mining is impractical (U.S. Department of the Interior, Bureau of Mines, 1977). Of this quantity, nearly three-quarters is in states west of the Mississippi River. Over one half of the coal that can be mined by underground methods is in states east of the Mississippi River. States with the largest coal reserves, ranked in order, are Montana, Illinois, Wyoming, West Virginia and Pennsylvania. These five states contain 71 percent of the nation's available coal. Deposits in Montana and Wyoming, represent 40 percent of the total reserve base and consist principally of lower rank subbituminous coals. Coals of the three eastern states are all of bituminous or higher rank. Pertinent details of the reserve base of coals in the U.S. are given in Table 5-5.

The fraction of coal that can be recovered from the reserve base is the "reserve" or the "recoverable reserve." Recoverability varies within a range of 40 to 90 percent of the reserve depending on the characteristics of the coal bed, the mining method, and restraints on mining a deposit imposed by natural and man-made features and restrictions. Mining experience in the U.S. indicates that at least one half of the U.S. reserve base of coal may be recovered. Estimates of recoverable reserves have been derived by applying a recoverability factor of 50 percent to underground deposits and 85 percent to surface deposits.* The recoverable reserves of coal in the U.S. amount to 270 billion tons; 150 billion tons in the western states and 120 billion tons in the eastern states. Details of the reserve base and recoverable reserves by state are given in Table 5-5.

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*A study of 200 underground mines shows an average recoverability of 57.0 ± 1.7 percent (Lowrie, 1968). With respect to the coal reserve base, average recovery by underground mining methods is expected to be about 50 percent owing primarily to coal left unmined to support the surface (U.S. Department of the Interior, Bureau of Mines, 1975). Recovery of coal by strip mining depends primarily on the ratio of the thickness of the overburden to that of the coal bed. Local topography is another factor that affects the recoverability of coal. Recovery, depending on the type of mining (contour stripping or area stripping) is expected to range between 80 and 90 percent (U.S. Department of the Interior, Bureau of Mines, 1975).

TABLE 5-5

RESERVE BASE AND RECOVERABLE RESERVES OF COAL IN THE UNITED STATES

WESTERN STATES				
STATE[a]	RESERVE BASE, MILLIONS OF TONS			RECOVERABLE RESERVE,[b] MILLIONS OF TONS
	DEEP	SURFACE	TOTAL	
Alaska	5,423.0	735.2	6,158.2	3,300
Arizona	-	325.5	325.5	280
Arkansas	251.7	140.5	392.2	250
Colorado	12,465.4	3,791.0	16,256.4	9,500
Iowa	1,736.8	465.4	2,202.2	1,300
Kansas	-	998.2	998.2	850
Missouri	1,418.0	3,596.0	5,014.0	3,800
Montana	70,958.9	49,610.1	120,568.9	78,000
New Mexico	2,150.1	2,447.9	4,598.0	3,200
North Dakota	-	10,145.3	10,145.3	8,600
Oklahoma	1,192.9	425.2	1,618.0	960
South Dakota	-	426.1	426.1	360
Texas	-	3,181.9	3,181.9	2,700
Utah	6,284.9	267.9	6.552.8	3,400
Washington	1,090.6	489.5	1,580.1	960
Wyoming	31,647.2	23,724.7	55,371.9	36,000
Total	134,619.5	100,770.4	253,389.9	153,000

EASTERN STATES				
STATE[a]	RESERVE BASE, MILLIONS OF TONS			RECOVERABLE RESERVE,[b] MILLIONS OF TONS
	DEEP	SURFACE	TOTAL	
Alabama	1,724.2	1,367.4	3,091.7	2,000
Illinois	53,128.1	14,841.2	67,969.3	39,000
Indiana	8,939.8	1,774.5	10,714.4	6,000
Kentucky-east	9,072.5	4,467.6	13,540.1	8,300
Kentucky-west	8,510.4	3,950.4	12,460.8	
Maryland	913.8	134.5	1,048.3	570
Ohio	13,090.5	6,139.8	19,230.2	12,000
Pennsylvania	29,302.7	1,534.4	30,837.1	16,000
Tennessee	627.2	337.9	965.1	600
Virginia	3,414.5	888.5	4,302.9	2,500
West Virginia	33,457.4	5,149.1	38,606.5	21,000
Total	162,181.1	40,585.3	202,766	120,000
Total, U.S.	296,976.3	141,361.0	438,337.3	270,000

SOURCE: U.S. Department of the Interior, U.S. Bureau of Mines, 1977.

[a] Excludes Georgia (reserve base 0.9 million tons), Idaho (4.4 million tons), Louisiana (undetermined reserve base), North Carolina (31.7 million tons) and Oregon (17.5 million tons).

[b] Computed as 50 percent of underground reserve base plus 85 percent of surface reserve base.

5.2.2 Sulfur Content of U.S. Coals

Practically all coals contain sulfur found in one or more of three basic forms: organic combinations as part of the coal substance, inorganic pyrites or marcasite compounds, and sulfates (Lowry, 1963). Coals in the U.S. vary markedly in both the fractional content by weight of sulfur and the chemical form in which the sulfur is present. The pyritic sulfur and total sulfur content of coals is highest in bituminous coals of Pennsylvania age in the Appalachian and Interior coal basins (Averitt, 1973). Subbituminous coals and lignite of the Rocky Mountain and Northern Great Plains regions are characterized by a relatively low content of pyritic and total sulfur. The fraction of sulfur present in coal as sulfates, mainly sulfates of calcium and iron, rarely constitutes more than a few hundredths percent of the weight of coal (Lowry, 1963).

Coal with a sulfur content of 1 percent or less by weight is generally referred to as low-sulfur coal. Medium-sulfur refers to a sulfur content in the range of 1.1 to 3.0 percent, and high-sulfur refers to a sulfur content in excess of 3.0 percent (U.S. Department of the Interior, Bureau of Mines, 1975). On the basis of these definitions, 46 percent of the total reserve base of the United States is identified as low-sulfur coal, 21 percent as medium-sulfur coal, and an additional 21 percent as high-sulfur coal. The sulfur content of 12 percent of the reserve base is undetermined.

The major portion, or 84 percent, of the reserve base of low-sulfur coal is found in states west of the Mississippi River. (U.S. Department of the Interior, Bureau of Mines, 1975). Roughly 40 percent of all low-sulfur coal is amenable to surface mining, with the bulk of surface deposits again being in the West. In the East, only 16 percent of the reserve base of low-sulfur coal is recoverable by surface mining techniques. With respect to rank, 22 percent of the reserve base of low-sulfur coal is composed of bituminous coals and anthracite, and 78 percent is composed of subbituminous coals and lignite.

States with the largest quantities of low-sulfur coal are Alaska, Montana and West Virginia (U.S. Department of the Interior, Bureau of Mines, 1975). Montana with a reserve base of 102 billion tons of low-sulfur coal contains 51 percent of the base, West Virginia 7 percent, and Alaska 6 percent. Virtually all of the Montana and Alaska coals are of low rank, whereas all of the West Virginia reserve base is composed of high rank bituminous coal. An estimated 29 percent of the coal reserve base consists of coals with a sulfur content of 0.7 percent or less; and 17 percent of the base consists of coals with a sulfur content of 0.5 percent or less. The major portion of these coals is located in western states, principally Montana and Alaska. In the East, the reserve base of coal with a sulfur content less than 0.7 percent is estimated to be 8 billion tons, representing 6 percent of the national reserve base of such coal. Pertinent details of the characteristic sulfur content of U.S. coals are given in Table 5-6. The quantities shown in this table correspond to estimates of the reserve base derived from information available on January 1, 1974. These may differ somewhat from the later estimates of the reserve base given previously in Table 5-5.

5.2.3 Coal-Producing Regions

In various analyses presented throughout this statement, states with substantial reserves of coal are grouped into four regions--the Eastern, Eastern Midwest, Western Midwest, and Western. Individual states are included in a particular region on the basis of geographical location and pertinent characteristics of the coal reserve base. The state of Kentucky is divided into Kentucky-east and Kentucky-west; and these segments are included in the Eastern and Eastern Midwest regions, respectively. The states making up each of the four regions are listed in Table 5-7.

5.3 Air Quality

5.3.1 Ambient SO_2 Concentrations

A comparison of 1975 ambient SO_2 monitoring data with data for recent years shows that SO_2 concentrations in urban areas have decreased by an average of 30 percent since 1970. Sulfur dioxide levels improved rapidly in the 1970-1973 period and then leveled off as many areas came into compliance with the National Ambient Air Quality Standards (NAAQS) for SO_2 (primary: 80 $\mu g/m^3$--annual arithmetic mean; 365 $\mu g/m^3$--maximum 24 hour concentrations not to

TABLE 5-6

RESERVE BASE OF COAL IN THE UNITED STATES, BY STATE AND SULFUR CONTENT

STATE*	RESERVE BASE IN MILLIONS OF TONS BY SULFUR CONTENT IN PERCENT				TOTAL**
	≤1.0	1.1-3.0	<3.0	UNKNOWN	
WESTERN STATES					
Alaska	11,458.4	184.2	0	0	11,645.4
Arizona	173.3	176.7	0	0	350.0
Arkansas	81.2	463.1	46.3	74.3	665.7
Colorado	7,475.5	786.2	47.3	6,547.3	14,916.5
Iowa	1.5	226.7	2,105.9	549.2	2,884.9
Kansas	0	309.2	695.6	383.2	1,388.1
Missouri	0	182.0	5,226.0	4,080.5	9,487.3
Montana	101,646.6	4,115.0	502.6	2,166.7	108,396.2
New Mexico	3,575.3	793.4	0.9	27.5	4,394.8
North Dakota	5,389.0	10,325.4	268.7	15.0	16,003.0
Oklahoma	275.0	326.6	241.4	450.5	1,294.2
South Dakota	103.1	287.9	35.9	1.0	428.0
Texas	659.8	1,884.6	284.1	444.0	3,271.9
Utah	1,968.5	1,546.7	49.4	478.3	4,042.5
Washington	603.5	1,265.5	39.0	45.1	1,954.0
Wyoming	33,912.3	14,657.4	1,701.1	3,060.3	53,336.1
TOTAL	167,305.0	37,540.6	11,244.2	18,322.9	234,458.6
EASTERN STATES					
Alabama	624.7	1,099.9	16.4	1,239.4	2,981.8
Illinois	1,095.1	7,341.4	42,968.9	14,256.2	65,664.8
Indiana	548.8	3,305.8	5,262.4	1,504.1	10,622.6
Kentucky-east	6,558.4	3,321.8	299.5	2,729.3	12,916.7
Kentucky-west	0.2	564.4	9,243.9	2,815.9	12,623.9
Maryland	135.1	690.5	187.4	34.6	1,048.2
Ohio	134.4	6,440.9	12,634.3	1,872.0	21,077.2
Pennsylvania	7,318.3	16,913.6	3,799.6	2,954.2	31,000.6
Tennessee	204.8	533.2	156.6	88.0	986.7
Virginia	2,140.1	1,163.5	14.1	330.0	3,649.9
West Virginia	14,092.1	14,006.2	6,823.3	4,652.5	39,589.8
TOTAL	32,852.0	55,381.2	81,406.4	32,476.2	202,162.2
UNITED STATES					
	200,181.1	92,997.6	92,671.1	50,837.7	436,725.5

SOURCE: U.S. Department of the Interior, Bureau of Mines, 1975.
*Excludes Georgia, Idaho, Louisiana, North Carolina and Oregon
**Totals may not correspond exactly to the sum of entries because of rounding errors.

TABLE 5-7

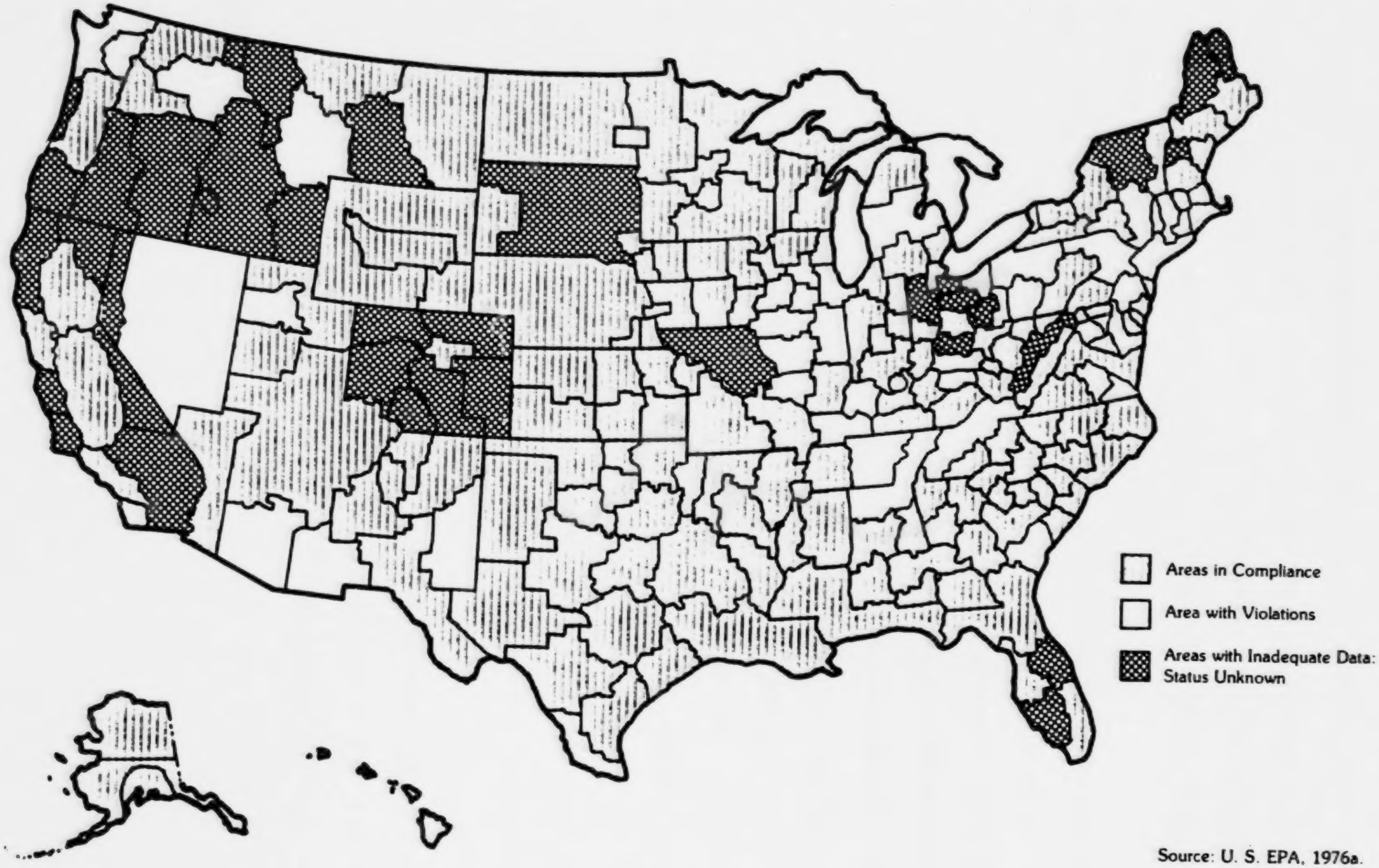
COAL PRODUCING REGIONS OF THE UNITED STATES

REGION	OTHER DESIGNATION	STATES ENCOMPASSED	COAL RESERVE BASE MILLIONS OF TONS
Eastern	Northern Appalachia Southern Appalachia and Alabama	Alabama	2,000
		Kentucky-east	8,300
		Maryland	570
		Ohio	12,000
		Pennsylvania	16,000
		Tennessee	600
		Virginia	2,500
		West Virginia	21,000
		TOTAL	62,970
Eastern Midwest	Interior Basin	Illinois	39,000
		Indiana	6,000
		Kentucky-west	7,600
		TOTAL	52,600
Western Midwest	Bureau of Mines Districts 12, 14, and 15	Arkansas	250
		Iowa	1,300
		Kansas	850
		Missouri	3,800
		Oklahoma	960
		Texas	2,700
		TOTAL	9,860
Western	Northern Great Plains The Rockies and The Pacific	Alaska	3,300
		Arizona	280
		Colorado	9,500
		Montana	78,000
		New Mexico	3,200
		North Dakota	8,600
		South Dakota	360
		Utah	3,400
		Washington	960
		Wyoming	36,000
		TOTAL	143,600
United States			270,000

be exceeded more than once per year; secondary 1300 $\mu g/m^3$--maximum 3-hour concentration not to be exceeded more than once per year). The available data indicate that SO_2 levels were relatively stable for the nation as a whole during 1975. Trends in SO_2 appear to have leveled off or in some cases increased slightly, apparently because of the failure or inability to use clean fuels in some areas of the country or the installation of more advanced control measures in an effort to meet air quality standards (U.S. Environmental Protection Agency, 1976).

The status of compliance with ambient air quality standards for SO_2 is shown in Figure 5-3. This map should not be used to determine nonattainment areas because it has been created to reflect the highest measured ambient concentrations in the 3-year period (1974-1976). More current information may show that the counties are or are not violating standards. This figure was prepared using data that were available from the U.S. Environmental Protection Agency's National Aerometric Data Bank (NADB) in September 1977. These data were supplemented with updated information from state reports provided by the EPA Regional offices.

The second maximum 24-hour average measured in the country in the period 1974-1976 was used as the summary statistic. This average relates to the short-term 24-hour average standard of 365 $\mu g/m^3$, which is not to be exceeded more than once per year. This was used instead of the annual mean, which could be compared with the SO_2 annual mean


▨ Areas in Compliance
☐ Area with Violations
▩ Areas with Inadequate Data: Status Unknown

Source: U. S. EPA, 1976a.

FIGURE 5-3

AIR QUALITY CONTROL REGIONS:
STATUS OF COMPLIANCE WITH AMBIENT AIR QUALITY STANDARDS FOR SULFUR DIOXIDE

primary NAAQS, because many SO_2 monitors did not collect sufficient data to meet the NADB validity criteria for calculating an annual mean. The criteria require that at least 75 percent of the total possible data be available to calculate an annual mean. Further, the 24-hour aveage NAAQS is more likely to be violated than the annual standard.

Data are available for most of the nation except some areas of the West and Northwest. An examination of the sulfur dioxide map indicates that most areas are not showing violations of the short-term NAAQS. Of the 834 counties with SO_2 data, 60 had second maximum 24-hour averages violating the 24-hour primary standard. Areas not in compliance are generally in industrial areas of the midwest and the western part of the country where the principal sources are smelting operations.

5.3.2 SO_2 Emissions

In 1976, the SO_2 emissions from electric utilities were estimated to be 13.6 million metric tons, which represented about 64 percent of the estimated national total of SO_2 emissions (Teknekron, 1978; EPA 1976).

An Integrated Technology Assessment computerized model (Teknekron, 1977) was used to project SO_2 emissions from all operating utility steam generators. This model calculated the total national and regional SO_2 emissions from these sources and the results are presented in Table 5-8 and Figure 5-4.

TABLE 5-8

REGIONAL SO_2 EMISSIONS

(Million Metric Tons Per Year)

Region	1985	1990	1995	2000
a. Moderate-Growth Rate				
NE	0.25	0.31	0.25	0.26
MA	1.70	1.66	1.62	1.69
SA	3.62	3.53	3.73	3.80
ENC	3.96	3.79	3.69	3.61
ESC	2.44	2.38	2.28	2.00
WNC	1.61	1.58	1.70	1.83
WSC	0.95	1.52	1.73	1.91
NM	0.09	0.13	0.18	0.24
SM	0.23	0.30	0.28	0.28
PA	0.31	0.31	0.33	0.29
Nation	15.2	15.5	15.8	15.9
b. High-Growth Rate				
NE	0.25	0.26	0.32	0.44
MA	1.67	1.62	1.72	1.87
SA	4.04	4.19	4.67	5.18
ENC	4.29	4.75	5.45	6.14
ESC	2.43	2.28	2.26	2.44
WNC	1.56	1.63	1.93	2.29
WSC	0.94	1.84	2.71	3.49
NM	0.07	0.14	0.28	0.42
SM	0.23	0.31	0.38	0.56
PA	0.32	0.43	0.60	0.90
Nation	15.9	17.5	20.3	23.8

Source: Teknekron, 1978.

These results lead to the following conclusions about total national emissions from electric power generation assuming no revision to the NSPS.

- National emissions of SO_2 from electric power plants will increase from 1976 partial compliance levels (about 13.6 million metric tons) at about 2 percent per year until 1985, if electricity demand grows at 5.8 percent per year until 1985.
- Under moderate demand growth and the present emission standards national SO_2 emissions will increase at approximately 0.4 percent per year from 1985 to 2000.
- With moderate demand between 1985 and the year 2000 eemissions are projected to decline slightly or remain relatively constant in all regions of the country except the South Atlantic (SA) and western midwest and mountain states (WNC, WSC, NM, SM).
- Under high demand growth after 1985 (5.5 percent per year in total demand and roughly 6 percent per year in coal-fired generation), national SO_2 emissions under current standards will increase at approximately 2.5 percent per year.
- With a high growth between 1985 and the year 2000, SO_2 emissions are projected to increase in every region of the country except the east south central (ESC) region. The western midwest and mountain states again would show the largest percent increase in SO_2 emissions, but large increases in the magnitude of emissions would occur in the eastern north central (ENC) states as well.

5.3.3 Air Quality Modeling Results

The relationship between emissions and resultant air quality is complex and dependent upon many conditions such as emission height, temperature and velocity, wind speed and direction, and terrain topography. To relate emissions to predicted air quality levels in a geographic area, various mathematical computer models have been developed. These models are useful in indicating air quality concentrations at points where no actual measurements are available or for predicting air quality impacts based on future emissions. However, a process of calibration of the model through comparisons with real data at selected geographic locations is desirable to reflect actual conditions at a location. When actual data are not available, as in predicting the effects of a new source, the results may be less reliable. In addition, factors such as atmospheric stability, changing terrain topography (e.g., water to land or flat to mountainous) and variations in wind direction and speed over time result in uncertainty, especially over longer averaging periods. Because of these uncertainties, the results obtained from these models must be used cautiously. They do illustrate trends and the relative air quality impact from steam generator emissions in a localized area and should be treated as such.

A series of dispersion analyses to estimate the effects of typical power plants meeting the current emissions standard on resulting air quality is presented in Table 5-9 (EPA, 1977a; 1977b). Hypothetical plants of three sizes were considered: 25 MW, 500 MW,, and 1000 MW. The entries in the table are estimates of the concentrations at ground level for the highest 3-hour average, the highest

TABLE 5-9

AIR QUALITY IMPACT - $\mu g/m^3$ (% FEDERAL AMBIENT AIR QUALITY STANDARD-SO_x)

Air Quality Averages	Atlanta/Athens		Evansville-Nashville		Cleveland-Buffalo		Dallas Oklahoma City		Bismarck		Tampa		Flint	
25 MW	Reheat	No Reheat	Reheat	No Reheat	Reheat	No Reheat	Reheat	No Reheat	Reheat	No Reheat	Reheat	No Reheat	Reheat	No Reheat
3-hour	110(8)	160(12)	84(6)	132(10)	78(6)	115(9)	89(7)	130(10)	91(7)	110(8)	74(6)	95(7)	89(7)	140(11)
24-hour	30(8)	40(11)	18(5)	28(8)	18(5)	24(7)	19(5)	24(7)	14(4)	19(5)	17(5)	21(6)	22(6)	30(8)
Annual	1.4(2)	2.0(3)	1.5(2)	2.0(3)	1.6(2)	2.0(3)	2.9(4)	3.6(5)	1.2(2)	1.4(2)	1.2(2)	1.5(2)	1.4(2)	1.8(2)
500 MW														
3-hour	220(17)	320(25)	210(16)	280(22)	270(21)	320(25)	210(16)	270(21)	200(15)	260(20)	160(12)	190(15)	180(14)	210(16)
24-hour	43(12)	65(18)	30(8)	47(13)	34(9)	41(11)	36(10)	65(18)	26(7)	36(10)	25(7)	42(12)	33(9)	50(14)
Annual	1.6(2)	2.7(3)	1.6(2)	2.5(3)	1.1(1)	1.7(2)	2.0(3)	2.9(4)	0.6(1)	0.9(1)	1.5(2)	2.3(3)	1.3(2)	2.1(3)
1000 MW														
3-hour	370(28)	480(37)	330(25)	390(30)	260(20)	560(43)	320(25)	360(28)	250(19)	390(30)	240(18)	310(24)	260(20)	400(31)
24-hour	55(15)	81(22)	42(12)	67(18)	38(10)	70(19)	68(19)	89(24)	39(11)	53(15)	35(10)	50(14)	50(14)	68(19)
Annual	2.1(3)	3.1(4)	2.2(3)	3.2(4)	1.4(2)	2.0(3)	2.6(3)	3.9(5)	0.7(1)	1.0(1)	2.2(3)	3.2(4)	1.7(2)	2.5(3)

Assumptions: CRSTER Model
Flat terrain and single stack
1964 Meteorological Data (Highest 3-hour and 24-hour average)

Plant Size(MW)	Stack Height(M)	Stack Height(M)	Stack Temperature(^oK)		Stack Gas Velocity (M/Sec)	
			w/Reheat	w/o Reheat	w/Reheat	w/o Reheat
25	75	1.48	325	353	20	21.7
500	175	6.62	325	353	20	21.7
1000	175	6.62	325	353	20	21.7

Source: EPA, 1977a, EPA 1977b.

24-hour average, and the annual average concentration for different plant sizes, emission concentrations, and geographic areas. These concentrations are incremental and would be in addition to the ambient concentration of the location (e.g., that concentration present if the plant were not there).

With reference to Table 5-9, several aspects of the results bear mentioning. First, it is apparent that the air quality impact is not linearly proportional to plant size. This phenomenon reflects the greater effective stack height (taller stack and greater plume rise) of the larger plants. Another significant feature of the results is the lower impact for the reheated exhaust streams. This reflects the greater plume rise of the hotter gas. Finally, it is evident that the estimated impacts vary considerably from one meteorological data base to another. This last result may be peculiar to the year 1964, which was used. Thus, several different years' data would have to be analyzed before geographical differences could be definitely established.

The highest 3-hour average concentration indicated in Table 5-9 is 560 $\mu g/m^3$ for the Cleveland-Buffalo meteorological data, a 1000-MW plant, and no reheat case. This is 43 percent of the allowable 3-hour Federal secondary standard. The 24-hour worst case result is for the Dallas-Oklahoma City meterology, a 1000-MW plant and no reheat. The 89 $\mu g/m^3$ concentration is 24 percent of the Federal 24-hour primary. Finally, for the annual primary Federal air quality standard, the highest value in the Table is 3.6 to 3.9 $\mu g/m^3$, or 5 percent for the Dallas-Oklahoma City 25-MW and 1000-MW cases. Even with the inaccuracies that are inherent in the results, the table indicates that a power plant is more likely to cause a violation of the 3-hour SO_2 standard than either of the longer term standards. The specific likelihood and number of violations would be a function of the preexisting ambient air quality at the time and place that these worst case meteorological conditions occur. Should multiple units be employed, consideration of the distances between stacks and their relative locations with respect to worst case wind patterns becomes important.

The additional impact upon ambient air quality from multiple stack emission sources is difficult to quantify since the results would be very sensitive to site-specific factors such as the relative location of the stacks to wind patterns, the relative stack heights, and the effective plume heights. If the stacks were in a line with the wind and all other factors were equal, a substantial additive effect would occur with the magnitude of the additional concentration dependent on meterological conditions and distance between the sources. A much smaller impact would occur if the same wind were perpendicular to the same line of stacks.

5.4 Present Water Environment

Essentially four kinds of water management systems are available to the power industry. These water management systems differ in the relative use of once-through cooling and recirculating water cooling systems.

System #1. All water used in the power plant is managed in a once-through system (Figure 5-5).

System #2. Recirculating cooling water at 2.5 cycles of concentration with once-through ash handling system and once-through general services water is used (Figure 5-6).

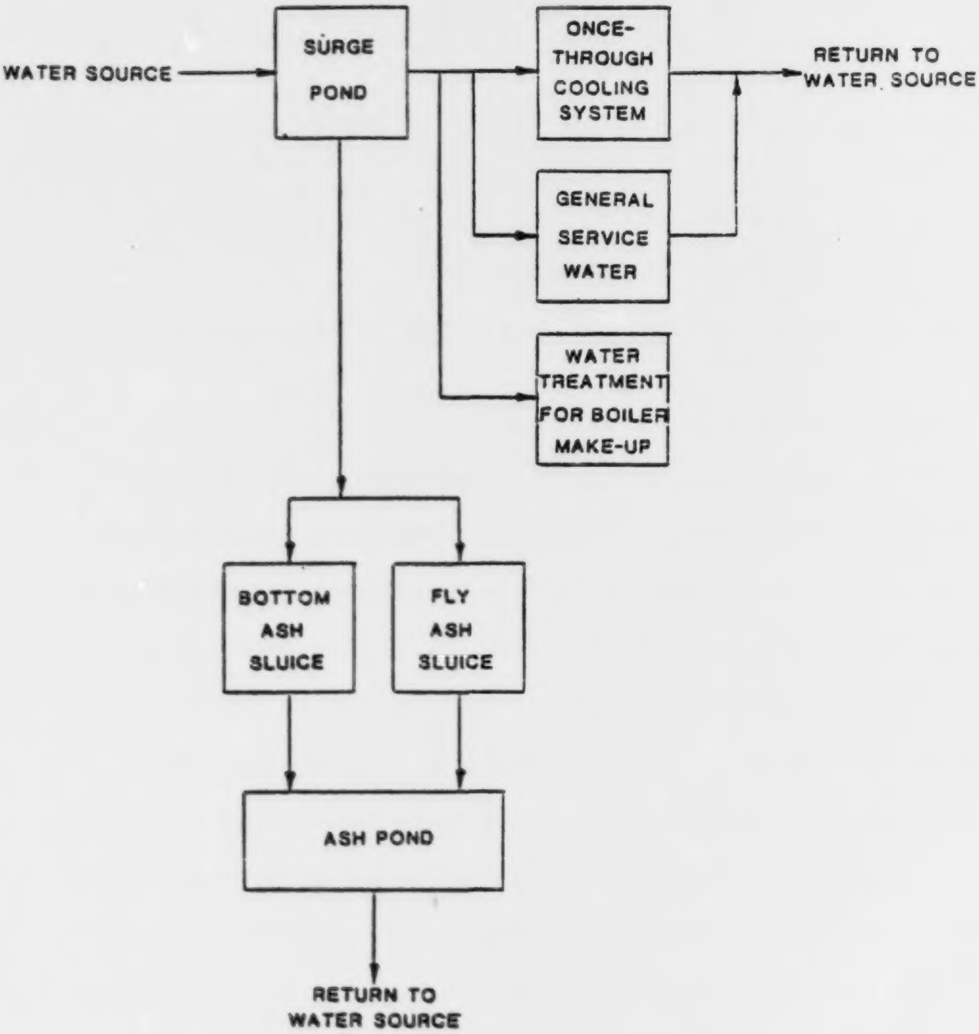
System #3. Recirculating cooling water at 5.0 cycles of concentration, 50 percent recirculating of ash handling water and the circulating of general service water blowdown to ash handling and the recirculating of general service water blowdown to ash handling system is used (Figure 5-7).

System #4. All water of the power plant is recirculated (Figure 5-8).

5.4.1 Water Quality

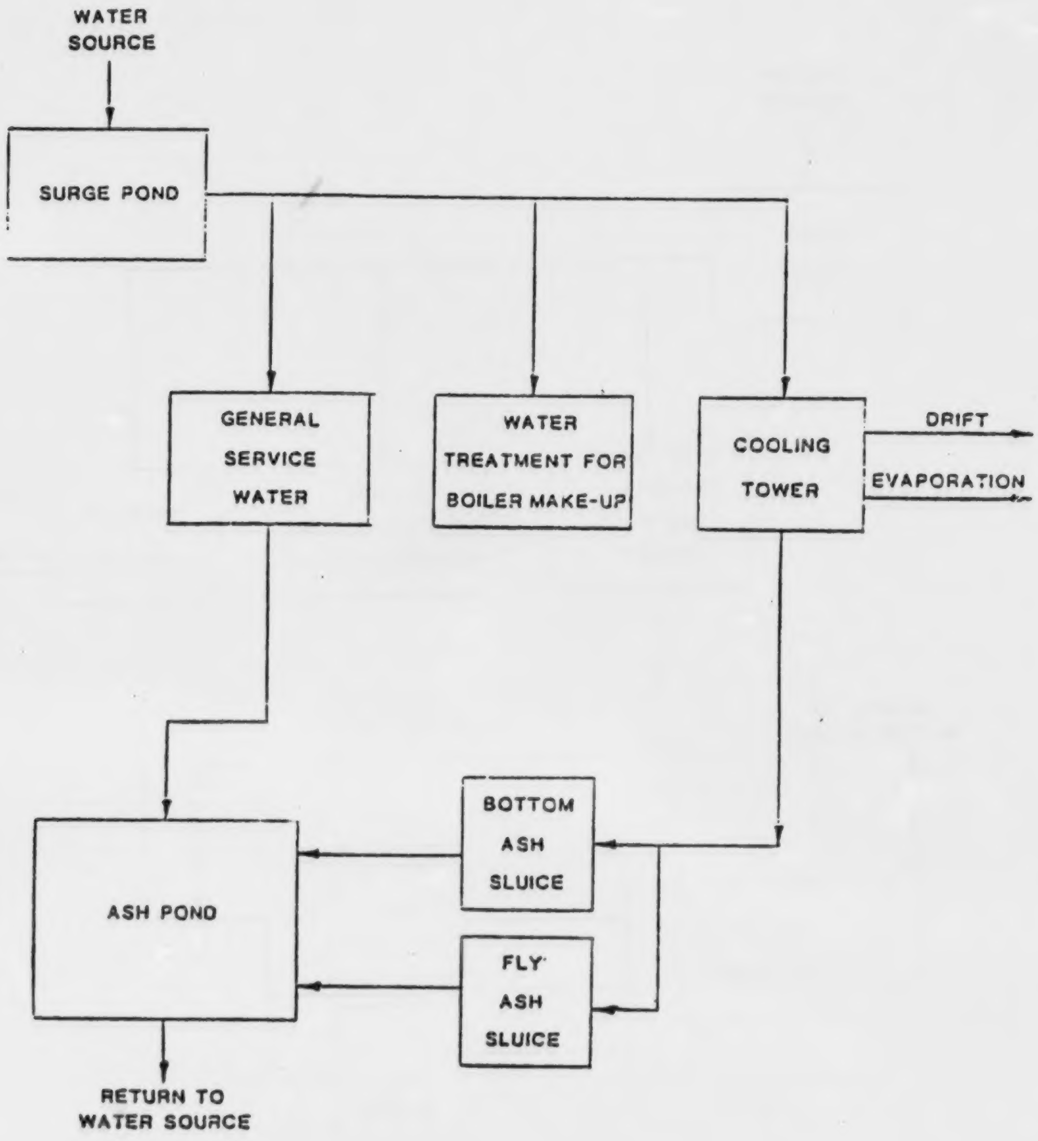
5.4.1.1 Unit Power Plant Water Requirements. In coal-fired steam/electric power plants, the heat of combustion produces steam to power turbine generators. The steam is subsequently condensed and returned to the boiler for further service. Approximately 45 percent of a fossil-fuel fired generating station's energy is removed and ultimately discharged to the environment by the condenser cooling system. To calculate the total cooling water requirement, a power plant efficiency of 37 percent was used. For a 500-MWe power plant, 610 MW (35 MM Btu/min) heat removal capacity is required. If a 10°C (20°F) rise in cooling water temperature is assumed in the condenser, a circulating flow of 13 m^3/s (210,000 gpm) is required.

In once-through cooling systems, the makeup water requirement is equal to the circulating rate, i.e., 13 m^3/s (210,000 gpm).


WATER SOURCE
SURGE POND
ONCE-THROUGH COOLING SYSTEM
RETURN TO WATER SOURCE
GENERAL SERVICE WATER
WATER TREATMENT FOR BOILER MAKE-UP
BOTTOM ASH SLUICE
FLY ASH SLUICE
ASH POND
RETURN TO WATER SOURCE

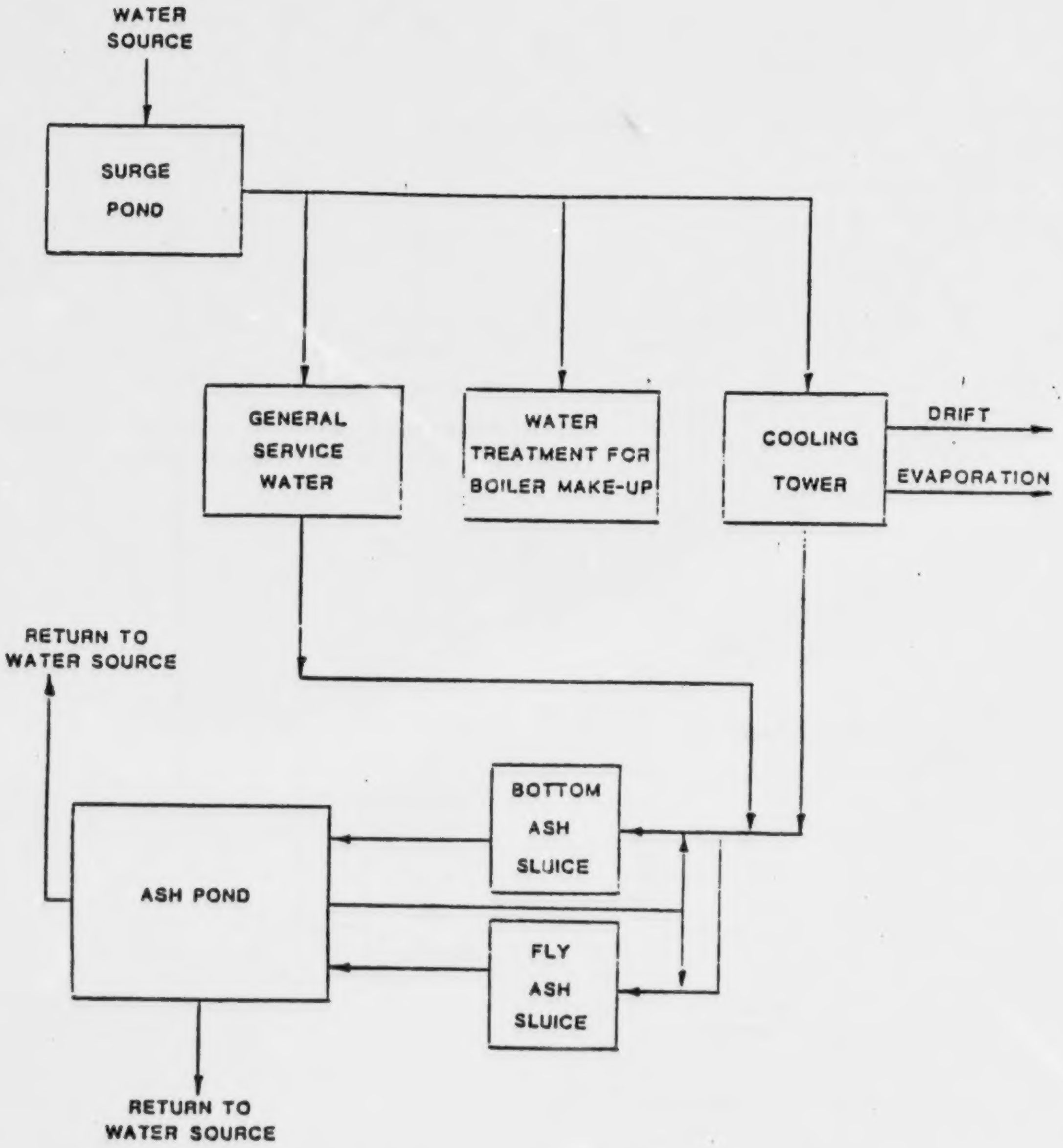
Source: Radian, 1977c,

Figure: 5-4 System #1-Once-Through Water Management.


WATER SOURCE
SURGE POND
GENERAL SERVICE WATER
WATER TREATMENT FOR BOILER MAKE-UP
COOLING TOWER
DRIFT
EVAPORATION
BOTTOM ASH SLUICE
FLY ASH SLUICE
ASH POND
RETURN TO WATER SOURCE

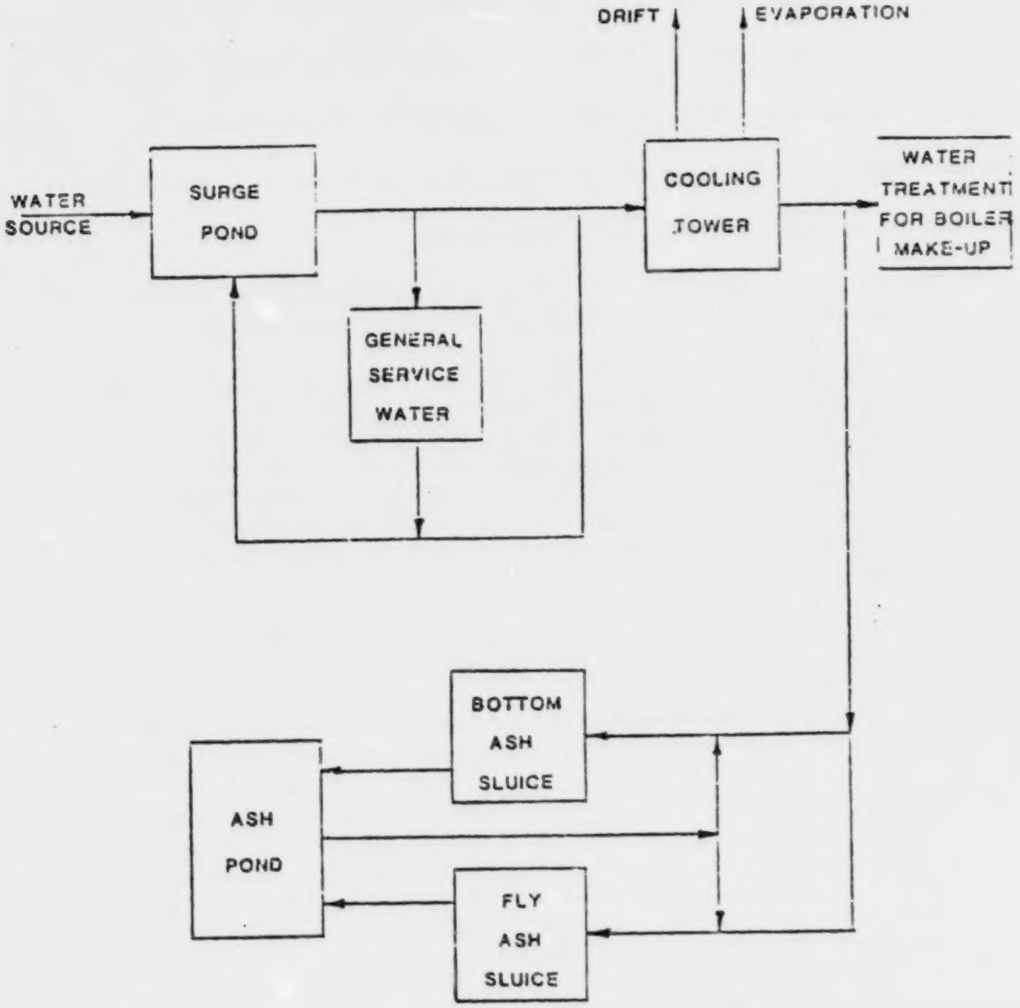
Source: Radian, 1977c.

Figure: 5-5 System #2-Partial Recirculatory Water Management.


WATER SOURCE
SURGE POND
GENERAL SERVICE WATER
WATER TREATMENT FOR BOILER MAKE-UP
COOLING TOWER
DRIFT
EVAPORATION
RETURN TO WATER SOURCE
BOTTOM ASH SLUICE
ASH POND
FLY ASH SLUICE
RETURN TO WATER SOURCE

Source: Radian, 1977c.

Figure 5-6 System #3-Recirculatory Water Management,


DRIFT
EVAPORATION
WATER SOURCE
SURGE POND
COOLING TOWER
WATER TREATMENT FOR BOILER MAKE-UP
GENERAL SERVICE WATER
BOTTOM ASH SLUICE
ASH POND
FLY ASH SLUICE

Source: Radian, 1977c.

Figure 5-7 System #4-Zero Discharge Water Management.

The ash handling system of a coal-fired power plant uses water to make ash slurry consisting of 5 weight percent fly ash and 1 weight percent of bottom ash. Sluice water requirements for a number of different coals are found in Table 5-10. The water of the ash handling system can be managed several different ways:

1. Once-through ash sluicing water system where water makeup requirements are equal to water sluicing requirements.
2. The use of blowdown from the cooling tower in a once-through ash sluicing water system. Sometimes a high ash coal is burned which requires more water for ash sluicing than is available from the cooling tower blowdown. This additional water requirement is filled with raw water. Sometimes less water is required for ash sluicing than is provided by the blowdown of the cooling tower; excess blowdown water is ponded before it is discharged.
3. Cooling tower blowdown and general service water blowdown are the sources of water for ash sluicing. Fifty percent of the sluicing water is recycled. As with the previous ash handling water management system, certain coals (high ash coals) will require the addition of raw water for makeup.
4. Cooling tower blowdown is the source of water for ash sluicing makeup and the cooling tower operated at 13.5 cycles of concentration with the sluicing system being in a recycling mode. No raw water is required as sluicing water makeup when coal ash is low. Excess cooling tower blowdown is available for general service water.

The general services water system includes water used for condenser and boiler cleaning, water conditioning, boiler fireside and air preheater washing, auxiliary cooling system and general power plant water use. According to the date of a water recycle/reuse study (Noblett, 1976; Christman, 1977; Gathman, 1976), a reasonable estimate of the use of general service water is 95 $\mu cm^3/s$ (1.5 gpm)

TABLE 5-10

SLUICE WATER REQUIREMENT

Coal	Sluice Water Requirement					
	Fly Ash		Bottom Ash		Total	
	m^3/s	(gpm)	m^3/s	(gpm)	m^3/s	(gpm)
1	0.076	(1200)	0.125	(2000)	0.20	(3100)
2	0.049	(780)	0.082	(1300)	0.13	(2050)
3	0.085	(1350)	0.14	(2250)	0.23	(3600)
4	0.088	(1400)	0.15	(2400)	0.24	(3800)
5	0.045	(720)	0.076	(1200)	0.125	(2000)
6	0.046	(730)	0.076	(1200)	0.13	(2050)

The above values assume that 75 percent of the ash forms as fly ash and 25 percent ash is bottom ash.

Coal #1, 0.8% S (dry basis), 8,000 Btu/lb. (AR basis), 6% ash, 30% H_2O
Coal #2, 0.8% S (dry basis), 11,000 Btu/lb. (AR basis), 6% ash, 15% H_2O
Coal #3, 3.5% S (dry basis), 12,000 Btu/lb. (AR basis), 12% ash, 2.6% H_2O
Coal #4, 7.0% S (dry basis), 12,000 Btu/lb. (AR basis), 12% ash, 5.7% H_2O
Coal #5, 3.5% S (dry basis), 12,000 Btu/lb. (AR basis), 12% ash, 2.6% H_2O
Coal #6, 7.0% S (dry basis), 12,000 Btu/lb. (AR basis), 12% ash, 5.7% H_2O

Source: Radian, 1977 c.

per megawatt. Thus, for a 500-MW power plant, 0.048 m^3/s (750 gpm) of water would be used for general service water. It has been determined from a study of Georgia Power Company's Bowen Plant (Noblett, 1976) that 75 percent of the general service water could be used to meet ash sluicing or cooling tower makeup water requirements. This amounts to 0.035 m^3/s (560 gpm). The general service water system can have three types of water management systems:

1. Service water system operates as a once-through system.
2. The service water is recirculated to ash sluicing.
3. The service water is recirculated in the cooling tower.

Since the boiler water has to be blown down periodically to reduce the concentration of impurities, makeup water is required. For a drum type steam boiler, the blowdown rate is 0.1 percent of the steam generating rate. For a 500-MW plant operating at 37 percent efficiency, the makeup water requirement is 50 cm^3/s (9 gpm).

The total amount of makeup water required for the four alternative water management systems of a model power plant is shown in Table 5-11.

5.4.1.2 Water Requirements for FGD Systems. The makeup water required for five alternative FGD systems for the base case 500-MW power plant is shown in Table 5-12. Water comsumptions for the manageable FGD system (lime, limestone and double alkali) is quite similar, 0.035 to 0.038 m^3/s (560 to 613 gpm). The regenerable FGD

TABLE 5-11

BASE CASE: MODEL POWER PLANT WATER CONSUMPTION

System Number	System[a] Description	Cooling Water System		Ash Handling System		General Services Water		Boiler Makeup		Total Fresh Water Makeup Requirement	
		m^3/s	(gpm)	m^3/s	(gpm)	m^3/s	(gpm)	m^3/s	(gpm)	m^3/s	(gpm)
1	Once-through[b]	13	(210,000)	0.23	(3600)	0.047	(750)	0.0006	(9)	13.5	(215,000)
2	Partial Recirculatory[c]	0.44	(7,000)	0.069	(1100)	0.047	(750)	0.0006	(9)	0.56	(8,850)
3	Recirculatory[d]	0.32	(5,000)	0.021	(330)	0.047	(750)	0.0006	(9)	0.38	(6,100)
4	Zero Discharge[e]	0.25	(4,000)	0	(0)	0.012	(190)	0.0006	(9)	0.26	(4,200)

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[a] The base case is a 500-MW power plant operating at an efficiency of 37%; 3.5% sulfur coal; average heating value of 28 MJ/kg (12,000 Btu/lb).

[b] All power plant water systems are once-through.

[c] Recirculatory cooling at 2.5 cycles of concentration, once-through ash handling, and once-through general services water.

[d] Recirculatory cooling at 5.0 cycles of concentration, 50% recirculatory ash handling, and recycle of general service water blowdown to the ash handling system.

[e] All power plant water systems are recirculatory.

TABLE 5-12

BASE CASE: FGD SYSTEM MAKE-UP WATER REQUIREMENT

Water[a] Requirement	Lime Wet Scrubbing		Limestone Wet Scrubbing		Wellman-Lord Sulfite Scrubbing		Magnesia Slurry Absorption		Double Alkali Wet Scrubbing			
									Lime Regenerant		Limestone Regenerant	
	m^3/S	(gpm)	m^3/S	(gpm)	m^3/S	(gpm)	m^3/S	(gpm)	m^3/S	(gpm)	m^3/S	(gpm)
Evaporative loss	0.030	(480)	0.030	(480)	0.030	(480)	0.030	(480)	0.030	(480)	0.030	(480)
Loss in solid waste	0.005	(80)	0.005	(80)					0.005	(72)	0.005	(79)
Prescrubber blowdown					0.003	(54)	0.003	(54)	0.003	(54)	0.003	(54)
Cooling water blowdown					0.014	(220)						
Loss with solids drying					0.002	(34)	0.003	(45)				
Loss in product SO_2 stream					0.003	(5)						
SO_2 Conversion Requirement:												
Sulfuric acid					0.008	(130)	0.008	(130)				
Elemental sulfur					0.002	(3)	0.0002	(3)				
Total	0.035	(560)	0.035	(560)	0.058	(923)[d]	0.042	(709)[b,d]	0.038	(606)[c]	0.038	(613)[c]
					0.050	(795)[b,e]	0.036	(580)[e]				
Liquid-to-gas ratio required for scrubber - m^3/Nm^3 (gal/1000 scf)	0.005-0.015	(35-110)	0.005-0.015	(35-110)	0.004	(3)[f]	0.003-0.004	(20-30)	0.0007-0.002	(5-15)	0.007-0.002	(5-15)
					0.002	(15)[g]	0.002	(15)[g]	0.002	(15)[g]	0.002	(15)[g]

[a] The base case is for a 500 MW power plant operating at an efficiency of 37%, burning 3.5%, buring 3.5% sulfur coal with an average heating value of 28 MJ/kg (12,000 Btu/lb).

[b] Value is assumed for model plant calculations.

[c] The average of the two double alkali systems is used for model plant calculations.

[d] The total water requirement if sulfuric acid is produced.

[e] The total water requirement if sulfur is produced.

[f] Separate scrubbing loops are provided for each of three trays.

[g] Prescrubber.

systems use more water, 0.042 m^3/s (709 gpm) for the magnesia slurry system and 0.058 m^3/s (923 gpm) for the Wellman-Lord system.

The makeup water requirements for various model plants with FGD systems which meet the present standard of performance are presented in Table 5-13. The power plant makeup water requirements are for System #3 which includes recirculating cooling water at 5.0 cycles of concentration, 50 percent recirculation of ash handling water and reuse of general service water in ash handling. The total makeup water requirement is directly proportionaly to plant size but varies little with the type of FGD system.

5.4.1.3 National Power Plant Water Requirements. Presently, there are 29 operational FGD systems, which have a total generating capacity of 8914 MW. Only two plants with a total capacity of 235 MW, have regenerable FGD systems. Using the data in Table 5-13, the approximate consumption of water by the nonregenerable FGD systems is estimated to be 0.600 m^3/S (9570 gpm). The approximate water requirements for the magnesia slurry FGD system with a 120-MW generating capacity is estimated to be 0.0105 m^3/S (168 gpm), and for the 115 MW of generating capacity which has a Wellman-Lord FGD system the water requirement is estimated to be about 0.0143 m^3/S (172.5 gpm).

The utility simulation model was used to project the quantity of water that would be consumed by FGD systems to meet the existing NSPS in future years. Table 5-14 shows projections by region for

TABLE 5-13

MODEL PLANT SYSTEM WATER REQUIREMENTS[b]

Case	Power Plant Capacity MW	SO_x Control System	Coal[a] Type	System #3 Power Plant Makeup Water Requirement m^3/s	System #3 Power Plant Makeup Water Requirement (gpm)	SO_x Control System Makeup Water Requirement m^3/s	SO_x Control System Makeup Water Requirement (gpm)	Total Model System Makeup Water Requirement m^3/s	Total Model System Makeup Water Requirement (gpm)
1	1000	Lime	#3	0.76	(12,000)	0.069	(1,100)	0.82	(13,000)
2	1000	Limestone	#3	0.76	(12,000)	0.069	(1,100)	0.82	(13,000)
3	1000	Wellman-Lord	#3	0.76	(12,000)	0.095	(1,500)	0.88	(14,000)
4	1000	Magnesium Oxide	#3	0.76	(12,000)	0.082	(1,300)	0.82	(13,000)
5	1000	Double Alkali	#3	0.76	(12,000)	0.076	(1,200)	0.82	(13,000)
6	500	Lime	#3	0.38	(6,100)	0.034	(540)	0.42	(6,600)
7	500	Limestone	#3	0.38	(6,100)	0.034	(540)	0.42	(6,600)
8	500	Wellman-Lord	#3	0.38	(6,100)	0.048	(760)	0.43	(6,800)
9	500	Magnesium Oxide	#3	0.38	(6,100)	0.042	(670)	0.43	(6,800)
10	500	Double Alkali	#3	0.38	(6,100)	0.037	(590)	0.42	(6,700)
11	100	Lime	#3	0.076	(1,200)	0.0069	(110)	0.082	(1,300)
12	100	Limestone	#3	0.076	(1,200)	0.0069	(110)	0.082	(1,300)
13	100	Wellman-Lord	#3	0.076	(1,200)	0.0095	(150)	0.088	(1,400)
14	100	Magnesium Oxide	#3	0.076	(1,200)	0.0088	(140)	0.088	(1,400)
15	100	Double Alkali	#3	0.076	(1,200)	0.0076	(120)	0.082	(1,300)
16	25	Lime	#3	0.019	(300)	0.0017	(27)	0.021	(330)
17	25	Limestone	#3	0.019	(300)	0.0017	(27)	0.021	(330)
18	25	Wellman-Lord	#3	0.019	(300)	0.0024	(38)	0.021	(340)
19	25	Magnesium Oxide	#3	0.019	(300)	0.0023	(37)	0.021	(340)
20	25	Double Alkali	#3	0.019	(300)	0.0019	(30)	0.021	(330)

[a] Coal type #3: 3.5% S; 28 MJ/kg (12,000 Btu/lb); 12% ash; 2.6% H_2O.

[b] 76% of sulfur removed to meet present NSPS of 1.2 lb $SO_2/10^6$ Btu.

Source: Radian, 1977c.

TABLE 5-14

WATER CONSUMED BY FGD SYSTEMS

(Thousand acre-feet per year)[a]

REGION	1990	1995	2000
a. Moderate-Growth Rate (520 ng/J-1.2 lb $SO_2/10^6$ Btu)			
NE	3.23	3.84	4.64
MA	21.5	23.1	25.6
SA	13.6	11.3	10.5
ENC	12.4	12.7	12.9
ESC	5.73	5.59	4.67
WNC	negligible	negligible	negligible
WSC	11.4	11.4	11.5
NM	5.07	5.51	5.36
SM	20.0	18.9	17.1
PA	negligible	negligible	negligible
Nation	92.9	92.3	92.3
b. High-Growth Rate (520 ng/J-1.2 lb $SO_2/10^6$ Btu)			
NE	3.77	6.52	11.9
MA	9.28	6.59	4.11
SA	14.6	11.5	12.4
ENC	13.8	29.2	48.5
ESC	0.918	0.282	0.0856
WNC	negligible	negligible	negligible
WSC	11.3	11.5	11.5
NM	5.39	5.44	5.50
SM	19.9	18.3	16.8
PA	negligible	negligible	negligible
Nation	79.0	89.3	111.

[a] Metric units are not used because of the convention of using acre-feet for water supply data; 1 acre-foot= 1,234 cubic meters.

Source: Teknekron, 1978.

both the moderate- and high-growth scenarios. The assumptions used in making these projections and descriptions of the regions appear in Appendix J.

There are only two areas in the U.S. where the water consumed by FGD systems is negligible, the West North Central and Pacific regions. The impact that these water demands would have upon the water supplies in the respective regions, cannot be determined from the above data, but critical areas in terms of the limited supply of water would include areas in California to the north, the southern mountain regions, and southern and central inland parts of the state.

5.4.2 Water Quality

A power plant has a number of different water systems producing wastewater streams that vary in quality according to the type of water management system. The water quality of these wastewater streams reflects the water use within the system. A once-through cooling water system produces an effluent that is similar in water quality to the influent; the effluent may contain only small amounts of corrosive products, corrosion inhibitors and biocides. In a recirculatory cooling water system, the effluent water quality is not the same as that of the influent. Dissolved solids build up to 1500 to 10,000 ng/l (1500 to 10,000 ppm). Soluble gases and particulates enter the water from the air. Corrosion and scale inhibitors (chromate, zinc, phosphate, silicates, certain proprietary organics for corrosion inhibitors, inorganic polyphosphates, chelating agents, polyelectrolyte antiprecipitants, and organic/polymer dispersants for scale-inhibitors) may also be present. The quality of bottom ash sluice water effluent is similar to its influent water, but fly ash sluice water effluent differs in water quality from its influent water as its turbidity is greatly increased and as it contains salts of sodium, potassium, calcium, and magnesium dissolved from the fly ash. The sedimentation clarifier underflow water from the water conditioning system has high concentrations of suspended solids and traces of flocculent and coagulant (alum, aluminate, copper or ferric chloride). Filtration backwash water in the water conditioning system has high concentrations of suspended solids. The lime/lime-soda softening clarifier underflow of the water conditioning system has a hardness of about 50 mg/l ($CaCO_3$), a pH of 10 and traces of flocculants and coagulants (alum, aluminate, copper or ferric chloride). The ion exchange regeneration waste stream of the water conditioning system has high concentrations of suspended solids in the backwash, and the spent regenerate has an extreme pH and high concentrations of eluted ions. The evaporation blowdown of the water conditioning system contains the same concentrated impurities that are found in the feedwater with a total dissolved solids concentration of 1000 to 2000 mg/l and a pH of 9 to 11. The boiler blowdown from the stream generation system has high concentrations of dissolved solids, traces of corrosion products, and chemicals used for scale control such as inorganic phosphates, EDTA or NTA; the pH is between 8.0 and 9.5. Equipment cleaning and washing waste streams of the general service water may have high suspended and dissolved solids, an extreme pH, high BOD and/or COD, and detergents. Coal pile runoff of the general service water may have high suspended and dissolved solid concentrations and a pH of 2 to 3.

With the addition of flue gas desulfurization (FGD) systems to a power plant, more water is used. The water quality of effluent streams from these FGD systems differs markedly. Properly operated lime/limestone wet scrubbers would not have a wastewater stream. However, when the system has to be purged, the content of the purge liquid would be equivalent to the scrubbing liquor. An example of the chemicals found in the scrubbing liquor of lime/limestone FGD systems are found in Table 5-15.

The prescrubbing system blowdown in a Wellman-Lord sulfide scrubber may contain 10,000 to 20,000 mg/l chloride ions, suspended solid concentrations of 5 percent, and trace amounts of the fly ash chemicals and scrubbing liquor. The condenser cooling water system blowdown of the Wellman-Lord system would have a water quality similar to that of the power plants cooling water blowdown. Prescrubber blowdown of the magnesia slurry system may have a chloride content of 10,000 to 20,000 mg/l, 5 percent suspended solids, and trace amounts of fly ash and scrubbing liquor. An intermittent purge of the magnesia slurry system may contain $MgSO_3$, $MgSO_4$ and trace

TABLE 5-15

RANGE OF CONCENTRATION OF CONSTITUENTS IN SCRUBBER LIQUORS STUDIED

Constituents	Range of Constituent Concentrations at Potential Discharge Points[a] (mg/l) Minimum	Maximum
Aluminum	0.03	0.3
Antimony	0.09	2.3
Arsenic	<0.004	0.3
Beryllium	<0.002	0.14
Boron	8.0	46.
Cadmium	0.004	0.11
Calcium	520.	3000.
Chromium (total)	0.01	0.5
Cobalt	0.10	0.7
Copper	<0.002	0.2
Iron	0.02	8.1
Lead	0.01	0.4
Magnesium	3.0	2750.
Manganese	0.09	2.5
Mercury	0.0004	0.07
Molybdenium	0.91	6.3
Nickel	0.05	1.5
Potassium	5.9	32.
Selenium	<0.001	2.2
Silicon	0.2	3.3
Silver	0.005	0.6
Sodium	14.0	2400.
Tin	3.1	3.5
Vanadium	<0.001	0.67
Zinc	0.01	0.35
Carbonate	<1.0	<10.
Chloride	420.	4800.
Fluoride	0.07	10.
Sulfite	0.8	3500.
Sulfate	720.	10,000.
Phosphate	0.03	0.41
Nitrogen (total)	<0.001	0.002
Chemical oxygen demand	60.	390.
Total dissolved solids	3200.	15,000.[b]
Total alkalinity (as $CaCO_2$)	41.	150.
Conductance mho/cm	0.003	0.015
Turbidity, Jackson Units	<3.	<10.
pH	3.04	10.7

[a] Samples obtained from: EPA/TVA, Shawnee, Steam Plant - venturi and spray tower; EPA/TVA Shawnee Steam Plant - turbulent contact absorber; Arizona Public Service Cholla Station - flooded disk scrubber and absorption tower; and Duquesne Light Phillips Station - single - and dual-stage venturi.

[b] Includes all soluble species.

Source: Radian, 1977c.

impurities. Prescrubber blowdown of the double alkali wet scrubbing system may have a chloride concentration of 10,000 to 20,000 mg/l, 5 percent suspended solids, and trace amounts of fly ash and scrubbing liquor. A purge stream from the double alkali wet scrubbing system would have high sodium sulfide, sodium sulfate and non-sulfur calcium salts. Solid-waste water of the double alkali wet scrubbing system would be similar to the solid-waste water of lime/limestone systems but not identical.

In the regenerable FGD systems, the enriched SO product stream can be used to make elemental sulfur or sulfuric acid. Elemental sulfur plants using the allied process would have no wastewater stream. Product acid cooling water system blowdown in sulfuric acid production would have the same water quality as the cooling water system blowdown of the power plant.

The effluents from all of the above systems can be treated and the purified water made available for recycling. Leaching of chemicals from solid wastes of lime/limestone and double alkali scrubbing systems can be controlled to some degree by chemical fixing and dump management procedures.

5.5 Land Use

Coal-fired steam generating plants require land for facilities used in power generation and for the disposal of solid wastes. The amount of land utilized is variable and depends upon the generating capacity of the plant, type of cooling system, sulfur and ash content of the coal, and the types of flue gas control systems employed. Plants using cooling ponds as the primary cooling system require more acreage than those using cooling towers; while power plants with cooling towers utilize more acreage than once-through cooling systems. The higher the concentration of ash and sulfur in coal, the more acreage required for solid waste disposal. In general, the larger the generating capacity of the coal-fired plant, the more acreage required for the site.

5.5.1 Land Used for the Physical Plant

A coal-fired electric generating plant with an SO_2 emission control system is composed of an administrative and boiler facility, turbine facilities an FGD system, an ash sluicing pond, a coal pile, a solid waste disposal area, a switchyard, a terminal line, a primary cooling facility, acreage for parking storage and other miscellaneous purposes. Excluding land which might be used for a cooling pond or cooling tower and a FGD disposal area, a typical 500-MW coal-fired unit with an FGD system would usually require less than 100 acres of land. The acreage occupied by mechanical draft circular cooling towers for the 500-MW plant would be approximately 1.4 acres (Shafer, Troxell and Howe, Co, 1977). Natural draft cooling towers would require 3.6 acres; a cooling lake would have a surface area of about 1000 acres. The acreage utilized in transmission lines is highly variable, but makes up a substantial part of the total acreage used for power generation.

5.5.2 Land Used for Solid Waste Disposal

All coal-fired electric generating plants need land for the disposal of solid wastes. Generating plants which have nonregenerable FGD systems (lime, limestone, and double alkali) produce a solid waste containing fly ash, unreacted lime or limestone, calcium sulfite and calcium sulfate and many chemicals introduced from fly ash. Regenerable FGD systems (Wellman-Lord/Allied and magnesia slurry) produce a little waste of purged solids which usually results from operator error. With the present SO_2 emission limitation of 520 ng/J (1.2 $SO_2/10^6$ Btu), the amount of solid wasteproduced by a 500-MW plant burning coal containing 3.5 percent sulfur and 14 percent ash is 2.334 x 10^6 tons/year when a limestone FGD system is utilized (Aerospace, 1977). In this case, 80 percent of the SO_2 in the flue gas is removed, and 302 acres of land with a solid waste depth of 30 feet are required for disposal of the solid waste for a 30-year period. However, 50 percent (dry weight) of this solid waste is composed of fly ash and should not be considered a product of coal-desulfurization. If 40 percent of the sulfur were removed prior to combustion by physical coal cleaning (PCC), the dry coal wash tailings would be 0.409 x 10^6 tons/year. Ash at the plant would be reduced to 0.7 x 10^6 tons/year and removal of the remaining sulfur by limestone scrubbing could produce 0.5 x 10^6 tons/year of dry scrubber wastes. Disposal of these solid wastes would require 182 acres of land at a waste depth of 30 feet for a 30-year period. Disposal of the combined

PCC and limestone FGD wastes requires approximately 36 percent less acreage than does the disposal of FGD limestone wastes alone. Solid wastes produced by double alkali FGD systems would require approximately the same acreage as that required for the lime/limestone FGD systems. Regenerable FGD systems would have minimal solid wastes.

5.5.3 Current Land Requirements

Presently there are 120 coal-fired electric generating plants (50,243 MW) which either have an operational FGD system or are in some stage of planning, construction, or operation. Only 29 of these plants (8914 MW) have operational FGD systems. The total amount of coal-fired electric generating capacity in the U.S. is 206,258 MW (Federal Energy Administration, 1977). Thus 4 percent of the total coal-fired electric generating capacity of the U.S. at this time has an operational FGD system. If 302 acres of land are required for solid waste disposal at a 500-MW plant burning 3.5 percent sulfur coal with an ash content of 14 percent and a limestone FGD system, the computed land requirements for the solid waste presently being produced in the operational FGD systems would be 4,350 acres. If 192 acres are required for solid waste disposal by a system combining PCC and limestone FGD, the computed acreage required would be 2,275. A substantial portion of this area would be required for ash disposal even if the plants did not have FGD systems.

5.5.4 Projected Land Requirements

With the present SO_2 emission limitation, the projected annual installed capacity of coal-fired generation will increase from 15,303 to 33,000 MW during the period 1978 to 1998 (see Table 5-16). This represents a 222 percent increase in annual installed capacity of coal-fired generation during this period. Based on this projection, the amount of dry solid waste generated in 1998 was calculated to be about 156 million tons. A computerized simulation model using more elaborate factors for projecting growth (including siting criteria) predicted that about 162 million tons of dry solid waste would be generated in the year 2000 if the NSPS remained at 520 ng/J (1.2 lb $SO_2/10^6$ Btu) (Teknekron, 1978). The acreage estimated to be required for disposal of the solid wastes as shown in Table 5-16 would increase from 7,324 acres in 1978 to 202,390 acres in 1998 if only low sulfur coal or limestone FGD systems were used to meet the existing NSPS. The projected amount of acreage required for the disposal of solid waste from coal-fired generating facilities from 1978 to 1998 is substantial and may increase the total land use by coal-fired electric power plants by 300 percent. As of February 1978, 92 percent of the generating capacity having operational FGD systems has limestone/lime scrubbers, and 80 percent of all scrubbers that should be operational by 1986 will be of the lime/limestone variety. Assuming that this trend continues, most of the FGD systems installed from 1978 to 1998 will be the solid waste generating variety (limestone, lime, and double alkali).

TABLE 5-16

PROJECTED LAND REQUIREMENTS FOR COAL-FIRED ELECTRIC GENERATING PLANTS

YEAR	ANNUAL INSTALLED GENERATING CAPACITY, MW	NUMBER OF EQUIV PLANTS	EASTERN COAL			WESTERN COAL			TOTAL ANNUAL REQUIREMENTS		
			DRY WASTE, tons x 10^6	ACRES	TOTAL ANNUAL ACREAGE REQUIRED FOR 30 yr	DRY WASTE, tons x 10^6	ACRES	TOTAL ANNUAL ACREAGE REQUIRED FOR 30 yr	DRY WASTE tons x 10^6	ACRES	ACREAGE REQUIRED FOR 30 yr
1978	15,303	30.6	4.642	201	6,017	1.009	44	1,307	5.651	245	7,324
1979	15,544	31.1	4.355	188	11,662	1.172	51	2,826	11 179	483	14,488
1980	21,101	42.2	5.417	234	18,684	1.789	77	5,144	18.385	793	23,828
1981	15,639	31 3	4.015	173	23,889	1.326	57	6,862	23.726	1024	30,751
1982	17,854	35.7	4.584	198	29,830	1.514	65	8,823	29.874	1288	38,653
1983	18,079	36.2	4.642	201	35,846	1.533	66	10,609	35.999	1555	46,655
1984	16,319	32.6	4.190	181	41,277	1.384	60	12,602	41.571	1796	53,878
1985	19,519	39.0	5.011	217	47,772	1.654	71	14,746	48.238	2083	62,518
1986	18,000	36 0	4.621	200	53,762	1.526	66	16,723	54.385	2349	70,485
1987	17,000	34 0	4.365	189	59,419	1.441	62	18,591	60.192	2601	78,010
1988	20,000	40.0	5.135	221	66,075	1.695	73	20,788	67.021	2895	86,863
1989	19,000	38.0	4.878	211	72,398	1.610	70	22,875	73.499	3176	95,273
1990	21,000	42.0	5.392	233	79,386	1.780	77	25,183	80.683	3485	104,568
1991	28,000	56.0	7.189	311	88,704	2.374	103	28,258	90.246	3899	116,962
1992	22,000	44.0	5.648	244	96,025	1.865	81	30,675	97.758	4223	126,700
1993	24,000	48.0	6.162	266	100,011	2.034	88	33,311	105.956	4577	133,322
1994	30,000	60.0	7.702	333	113,995	2.543	110	36,607	116.202	5020	150,602
1995	24,000	48.0	6.162	266	121,981	2.034	88	39,243	124.399	5374	161,224
1996	30,000	60.0	7.702	333	131,965	2.543	110	42,539	134.645	5817	174,504
1997	30,000	60.0	7.702	333	141,948	2.543	110	45,835	144.890	6260	187,783
1998	33,000	66.0	8.472	366	152,930	2.798	121	49,460	156.161	6747	202,390

SOURCE: Aerospace, 1977.

Along with the actual environmental impact of taking lands out of some other kind of production and using it for solid waste disposal, there are some potential environmental impacts associated with placing these solid wastes on the land. These potential environmental impacts would be mainly due to the chemical components of the coal and absorbent and would be associated with nonregenerable FGD systems (limestone, lime and double alkali) more than they would be with regenerable systems (Wellman-Lord/Allied and MgO).

The amount of solid waste generated by the regenerable systems is negligible. Limestone, lime and double alkali FGD systems produce a solid waste which is mostly composed of unreacted lime/limestone, calcium sulfite, calcium sulfate and chemicals from fly ash. In addition to these chemicals, the double alkali process has sodium carbonate in its waste. The relative amounts of these chemicals depends upon the control system, its design and operating variables and the type of coal burned. Ranges of chemical constituents found in FGD sludges from lime, limestone, and double alkali systems are shown in Table 5-17.

The chemical characteristics of ash depend largely on the geologic factors related to the coal used. The major constituents of ash are silicon, aluminum, iron and calcium; minor constituents are magnesium, titanium, sodium, potassium, sulfur and phosphorus. There can also be trace concentrations in the ash of elements such as arsenic, barium, beryllium, lead, mercury, cadmium and zinc. Studies

TABLE 5-17

RANGE OF CONCENTRATIONS OF CHEMICAL CONSTITUENTS IN FGD SLUDGES FROM LIME, LIMESTONE, AND DOUBLE-ALKALI SYSTEMS

Scrubber Constituent	Sludge Concentration Range Solid, (mg/kg[a]) Minimum	Maximum
Aluminum	-	-
Arsenic	0.6	52
Beryllium	0.05	6
Cadmium	0.08	4
Calcium	105,000	268,000
Chromium	10	250
Copper	8	76
Lead	0.23	21
Magnesium	-	-
Mercury	0.001	5
Potassium	-	-
Selenium	2	17
Sodium	-	48,000
Zinc	45	430
Chloride	-	9,000
Fluoride	-	-
Sulfate	35,000	473,000
Sulfite	1600	302,000
Chemical oxygen demand	-	-
Total dissolved solids	-	-

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[a] Solids analyses were conducted on six samples from six power plants burning eastern or western coal and using lime, limestone, or double-alkali scrubbing processes.

Source: Aerospace, 1977.

on the chemical composition of eastern and western coal reveal that eastern coal tends to have higher concentrations of arsenic, cadmium, mercury, and zinc than does western coal (Aerospace, 1977). It is expected that these differences in the coal will be reflected in the chemical makeup of the solid wastes resulting from the burning of these two kinds of coal.

5.6 Energy Consumption Associated with Control Measures

The energy requirements of different SO_2 emission control strategies are dependent upon the method of control, level of control, and coal composition (Radian, 1977b).

5.6.1 Flue Gas Desulfurization

In FGD systems there are six basic energy consuming processes.

- Raw material handling and feed preparation is that part of the process that involves receiving, storing, and preparing makeup reagents for the FGD system. Areas of energy utilization include the powering of conveyors, grinders, mixers, and pumps associated with the above operations.

- Particulate/chloride removal is a necessary step in regenerable systems to avoid the buildup of corrosive materials in the scrubbing liquors. The principal energy penalty for preremoval of particulates and chlorides involves the flue gas pressure drop and equipment power associated with venturi scrubbers and, in some cases, electrostatic precipitators or baghouses required to remove both substances.

- SO_2 scrubbing involves the actual removal of SO_2 from the flue gas. Various techniques are available with the principal energy penalties involving the operation of pumps, agitators, etc., to operate the absorber materials and pressure drops in the flue gas passing through the equipment.

- Reheat of the flue gas may be necessary to raise the gas temperature to that value that will prevent the formation of sulfuric acid misst and to provide a sufficient plume buoyancy. Several techniques such as steam injection, combustion of auxiliary fuels (oil or gas), and direct injection of hot combustion gases could be used to raise the flue gas temperature. All of these involve energy penalties that are very dependent on the required reheat temperature.

- Operation of fans, either induced or forced draft, is used to maintain gas flow through the scrubbing systems. The energy penalty to operate those fans is proportional to the exit gas velocity and temperature (which in turn is dependent on the FGD system design).

- Disposal/recovery of sulfur is dependent on the process used. Nonregenerable processes generate a sludge that can be disposed of at on-site holding ponds or, following sludge stabilization, at an off-site disposal facility. For the on-site disposal, energy is required to pump water and material to and from the settling pond as well as to operate agitators in the feed tanks. Off-site disposal would include the energy cost of transportation and power to operate holding tank agitators. Regenerable processes require energy to operate the sulfur recovery processes. In the Wellman-Lord/Allied process the energy requirements during the evaportation step are critical; while in the MgO process, oil-fired dryers and calciners are used to decompose $MgSO_3$ into MgO and the dilute SO_2 stream.

In general, the various FGD control alternatives have the following characteristics:

- Regenerable systems have a higher overall "energy penalty" than nonregenerable systems. This is due to the sulfur recovery stage of the process.

- Regenerable system energy costs are very sensitive to the sulfur content of the coal. Again these costs are most sensitive to the sulfur recovery stage of the process.

- Nonregenerable system energy costs are relatively independent of the sulfur content of the coal and the SO_2 removal level. The energy required to reheat the flue gases, operate the draft fans, and to scrub to remove particulate matter and chlorides, is independent of the coal sulfur content and SO_2 removal required. This energy comprises 65 to 90 percent of the total energy penalty.

Table 5-18 summarizes the calculated energy penalties as a function of plant size, coal sulfur content, and the 520 ng SO_2/J removal level. The values in the table are normalized to indicate the energy penalty per kilowatt generated. Numbers in parentheses are the penalties as a percentage of the power plant net heat rates (total plant heat rate divided by the generating capacity). The following points emerge from Table 5-18.

- There is relative independence of the energy penalty percentage with respect to power plant capacity. Regardless of the control type/coal sulfur content/process combination the energy penalty percentage on a kilowatt-generated basis is nearly constant across all the various power plant sizes.
- The smallest energy penalty is imposed by the use of nonregenerable FGD processes.
- The limestone process requires from 10 to 35 percent more energy than the other two nonregenerable process and indicates a slightly greater sensitivity to sulfur content and SO_2 control level. Doubling the coal sulfur content from 3.5 percent to 7.0 percent would cause a 10 percent increase in the energy penalty of a lime FGD system and a 30 percent increase in the energy penalty of a limestone-FGD process.
- Of the two regenerable processes, the Wellman-Lord/Allied process requires over twice the energy as the MgO process when 3.5 percent sulfur coal is burned.
- The 7 percent sulfur coal is an extreme worst case example. Most coal currently used by United States utilities is in the 2 to 3 percent sulfur range with a maximum of 5 percent.

TABLE 5-18

ENERGY PENALTIES FOR MODEL SO_2 CONTROL SYSTEMS (520 ng SO_2/J)

Coal	Control Technique	SO_2 Control Penalty, J/KW-S (% of energy input to controlled plant)			
		25MW	100M	500MW	1000MW
Nonregenerable					
3.5% Sulfur, 27.9 MJ/kg	FGD-Limestone	90 (3.3)	90 (3.3)	90 (3.4)	90 (3.1)
7.0% Sulfur, 27.9 MJ/kg	FGD-Limestone	120 (4.4)	120 (4.4)	110 (4.2)	110 (4.3)
3.5% Sulfur, 27.9 MJ/kg	FGD-Lime	90 (3.3)	90 (3.3)	80 (3.0)	80 (3.1)
7.0% Sulfur, 27.9 MJ/kg	FGD-Lime	100 (3.7)	100 (3.7)	100 (3.7)	90 (3.5)
3.5% Sulfur, 27.9 MJ/kg	D-A FGD	80 (2.9)	80 (3.0)	80 (3.0)	80 (3.1)
Regenerable					
3.5% Sulfur, 27.9 MJ/kg	MgO FGD	150 (5.5)	150 (5.5)	140 (5.3)	130 (5.1)
3.5% Sulfur, 27.9 MJ/kg	W-L/A FGD	320(11.8)	310(11.8)	310(11.7)	290(11.4)
Other Options					
0.4% Sulfur, 20.9 MJ/kg	Western Coal	170 (6.2)	NE	170 (6.4)	NE
0.6% Sulfur, 26.5 MJ/kg	Western Coal	150 (5.5)	NE	140 (5.3)	NE
2.2% Sulfur, 29.2 MJ/kg	Coal Cleaning/FGD Limestone	NE	NE	260 (9.8)	NE
2.2% Sulfur, 29.2 MJ/kg	Coal Cleaning/FGD Lime	NE	NE	260 (9.8)	NE

Uncontrolled power plant net heat rate:
25MW - 2720 J/KW-S
100MW - 2710 J/KW-S
500MW - 2640 H.KW-S
1000MW - 2550 J/KW-S
NE - Not examined.

5.6.2 Other Control Options

The use of low sulfur western coal and physical coal cleaning in conjunction with nonregenerable FGD are two other options for which the energy penalties associated with the western coal option are its generally lower heat content per kilogram of coal and the energy required to transport the coal to locations in the midwest and east. (The energy required to develop the transportation network such as trackbed improvements, roads, hopper cars, coal trucks, and handling facilities is not included in the analyses.) With physical coal cleaning, the energy penalty involves the energy required to clean the coal, the loss in some original heat content, and the probable need for some FGD system. The FGD system would require less energy than that required for raw coal due to the lower particulate removal required and the lower sulfur content of the cleaned coal.

The coal cleaning and coal transportation energy penalties were calculated using the assumptions indicated in Table 5-19. Using these assumptions a summary of energy penalties for these options was generated as a function of plant size, sulfur content, and SO_2 control level.

A comparison of the results shown in Table 5-20 show that both coal cleaning/FGD and the use of western coal have higher energy penalties than any of the nonregenerable FGD alternatives regardless of sulfur content. Physically cleaning coal in conjunction with a nonregenerable FGD system is shown to require about three times the energy demand when only the FGD process is used. The coal cleaning/FGD

TABLE 5-19

ANALYSIS ASSUMPTIONS FOR THE ENERGY PENALTY ASSOCIATED WITH COAL CLEANING AND WESTERN COAL TRANSPORTATION

Assumptions for Physically Cleaned Coals

	Physically cleaned 3.5% sulfur coal	Physically cleaned 7.0% sulfur coal
Moisture-Ash Free (MAF) Coal, wt. %	87.1	87.1
Ash, wt. %	6.6	6.6
H_2O, wt. %	6.3	6.3
Sulfur, wt. %	2.2	4.4
Heating Value, MJ/kg	29.2	29.2

(1) 278 Kg/S (500 ton/hour) plant size
(2) 50% ash removal
(3) 40% sulfur removal
(4) 95% energy recovery efficiency
(5) 50% of product coal is thermally dried
(6) Heat for thermal dryer is supplied by combusting product coal - 434 KJ/Kg (230 Btu/lb)
(7) Electric power required for a 278 Kg/S (500 ton/hour) plant is 2980 KW

Assumptions for Western Coal Transportation

(1) Distance is 2100 Km (1300 miles) - approximate distance between Four Corners area of New Mexico or eastern Montana and central Ohio.

(2) Unit train capacity is 91000 Kg (100 tons)/car - 100 cars.

(3) Five locomotives: .00021 M^3/S (200 gals/hr)/locomotive - full power
.000029 M^3/S (28 gals/hr)/locomotive - reduced power

(4) Eight hours loading/unloading - reduced power

(5) One hour per large city or federal inspection - reduced power

(6) One large city every 180Km (110 miles); one inspection every 800 Km (500 miles)

(7) Loaded speed: 48 Km/hr (30 mph); empty return speed: 96Km/hr (60 mph)

(8) One percent loss due to coal dust blow-off

(9) Heat content deisel fuel: 38 GJ/m^3 (138000 Btu/gallon)

SOURCE: Radian, 1977 b.

TABLE 5-20

ENERGY ASSOCIATED WITH 520 ng/J STANDARD (10^{18} JOULES)

YEAR	GENERATING INPUT ENERGY*	GENERATING INPUT ENERGY WITH FGD* (% TOTAL INPUT)	FGD ENERGY (% TOTAL INPUT)	TRANSPORTATION ENERGY** (% TOTAL INPUT)	TOTAL (% TOTAL INPUT)
MODERATE GROWTH SCENARIO					
1985	17	3.1(18)	0.15(0.9)	0.20(1.2)	0.35(2.1)
1990	21	3.6(17)	0.17(0.8)	0.25(1.2)	0.42(2.0)
1995	24	3.9(16)	0.19(0.8)	0.30(1.2)	0.49(2.0)
2000	29	4.4(15)	0.21(0.7)	0.35(1.2)	0.56(1.9)
HIGH GROWTH SCENARIO					
1985	17	2.7 (16)	0.13(0.8)	0.22(1.3)	0.35(2.1)
1990	25	3.5(14)	0.17(0.7)	0.37(1.3)	0.54(2.2)
1995	35	4.5(13)	0.21(0.6)	0.56(1.3)	0.77(2.2)
2000	48	5.9(12)	0.28(0.6)	0.78(1.2)	1.06(2.2)

*0.65 Plant Operating Factor; 0.35 Thermal Efficiency

** Includes Barging: 0.31×10^6 Joules/ton-mile; Rail: 0.383×10^6 Joules/ton-mile.

Based On: Teknekron, 1978.

option is relatively insensitive to doubling of the coal sulfur content. Raising the western coal sulfur content from 0.4 to 0.6 percent would lower the energy penalty by about 15 percent due to the higher energy content of the coal.

It should be noted that the sensitivity to the western coal energy penalty to transportation is such that halving the assumed distance (e.g., 650 miles) for transportation reduces the energy penalty by about one-half, or doubling the assumed distance (e.g., 2600 miles) causes an approximate doubling of the penalty.

5.6.3 Energy Penalty Projections (1987 and 1997)

While there are many variables and uncertainties associated with the mix of coals, the mix of SO_2 control methods, and future generating capacity growth, it is possible to obtain estimates of the relative impacts of using a specific coal type and control techology. The fact that the energy penalties of the various control techniques are relatively insensitive to the plant size when considered on a per kilowatt basis allows the analysis to be conducted as independent of the mix of various plant sizes that will be built in the future.

An analysis of the total installed generating capacity predicted for the years 1985, 1990, 1995, and 2000, has been performed (Teknekron, 1978). The analysis included consideration of regional coal availability and coal sulfur content differences, competing generating technologies, and costs. Based upon this study, projections of the generating capacity that would be controlled by FGD and overall transportation energy that would be required using the current standard NSPS are shown in Table 5-20.

Both moderate and high growth scenarios were used to project coal-fired electrical energy requirements. Of this energy requirement, only a certain portion would be controlled by FGD and is labelled in Table 5-20 as "Generating Input Energy With FGD." The FGD energy calculation assumed that nonregenerable processes using lime or limestone would predominate with regenerable processes accounting for 5 percent of the FGD control. The coal transportation energy calculation was based on an assumed "supply node" in a coal-supply area and centrally located "consumer nodes" in each consuming state.

The results indicate that the energy that would be expended for FGD under the current standard would amount to between 0.6 and 0.9 percent of total electrical energy generation with the values decreasing with time. The difference in the FGD controlled energy input between the moderate growth and high growth scenarios in 1985 is due to differences in the allocation of low sulfur coal to previously operating units and those subject to the NSPS.

6.0 ASSESSMENT OF ENVIRONMENTAL IMPACTS

The environmental impacts that may result from a revision to the NSPS for SO_2 emissions from coal-fired utility boilers vary with the level of the revised standard. Basically, the environmental impacts resulting from a revised standard are expected to be the same as those from the present standard, only their magnitude would change.

The following sections discuss the potential environmental impacts that may result from three alternative levels of the standard: 90 percent reduction of potential SO_2 emissions, 80 percent reduction of potential SO_2 emissions, and an emission limit of 220 ng/J (0.5 lb $SO_2/10^6$ Btu). The computerized utility simulation model employed to quantify environmental impacts resulting from the existing standard of 520 ng/J (1.2 lb $SO_2/10^6$ Btu) discussed in Chapter 5 was also used to quantify impacts of the alternative standards addressed in this chapter. The same forecasts for the electric utility industry were used (see Appendix J). The model predicts the environmental impacts that would result if alternative revised levels of the standard were met. The existing standard must be met if it is not revised; therefore, the impact of revising the standard is the difference between meeting the present NSPS and the revised NSPS. Consequently, in the following sections many references are made to the discussion of the existing environment presented in the previous chapter.

6.1 Impacts on Coal Resources and Transportation

Promulgation of the proposed standard is expected to give rise to changes in established patterns of coal resource development and coal movement throughout the country. While the present standard has been in effect, utilities have exercised the option of procuring low sulfur coal for the fuel steam generators that are subject to the standard. Economic and other considerations have tended to promote the movement of substantial quantities of these low sulfur coals from the western states to the East (Section 5).

A utility's decisions concerning the (1) selection of fuel for future power plants, (2) siting of these plants, and (3) logistics of fuel supply, are based on a set of complex technical, economic, regulatory, environmental and other issues. With regard to coal as a fuel, the costs of transportation from mine to power plant are important considerations influencing the expansion plans of many utility companies. These costs (discussed further in Chapter 7) increase with increasing distance over which coal is transported and with decreasing heat content of the coal. Notwithstanding the financial penalties, there is an increased reliance on low sulfur western coal with a relatively low heat content. Projections indicate that coal from the major producing western states will supply 35 percent of the total needs of the electric utility industry in 1985. Roughly one-third (31.3 percent) of the incremental production of coal in the West will cross the Mississippi River to the East (Section 5).

The revised standard is not expected to affect substantially the projected flow of coal to new generating units scheduled to be in operation on or before the early 1980s. In the ensuing years, however, an influence on regional patterns of incremental coal production and distribution is anticipated. The revised standard would preclude burning of most coals without flue gas desulfurization or without a combination of flue gas desulfurization and coal cleaning. This will tend to eliminate or diminish the economic and other incentives associated with the low sulfur option. As a consequence, both production and movement of low sulfur coals beyond 1985 would be affected.

These general conclusions are supported by a detailed study (ICF Inc., 1978) of the impacts of the proposed revised standard on coal markets and utility expansion plans. The study shows that such impacts would be sensitive to the forecast rate of growth in demand for electrical power beyond 1985, but are insensitive to whether the revised standard is set at a level of 90 percent reduction, 80 percent reduction, or a limit of 220 ng/J (0.5 lb $SO_2/10^6$ Btu). The greatest effects of the revised standard would be experienced if a high rate of growth in consumption of electrical energy is sustained beyond 1985. Comparisons are made in the study between a reference case based on a 5.8 percent annual rate of growth between 1975 and 1985 and a 3.4 percent growth thereafter; and a second case based on the same growth of 5.8 percent between 1975 and 1985 and a growth of 5.5 percent thereafter.

In the high growth scenario, national coal production under each of the three alternative revised standards is forecast to be less than the projected production under the current standard by 30 to 50 million tons per year in 1990, representing a reduction of about 2.5 percent (ICF, Inc., 1978). Some of this reduction results from a higher national average heat content of coal as production is shifted from western coals of lower heat content to eastern coals of higher heat content. Furthermore, more utility oil and gas is expected to be consumed as higher costs of coal-fired power plants make it economically competitive to increase the use of oil and gas in existing oil and gas steam plants.

In 1990 western low sulfur coal will not be competitive with locally available medium and high sulfur coals in new eastern and midwestern power plants required to install scrubbers to comply with a revised standard. Therefore, the amount of western coal shipped to and consumed in the East is predicted to be lower by 150 million tons in 1990, representing a decrease of 2.5 percent. The forecast on regional production, which indicates a shift from western coals to eastern and midwestern coals, is shown by the predictions in Table 6-1.

6.2 Air Quality

6.2.1 SO_2 Emissions

A computerized simulation model has been used to project SO_2 emissions in order to examine the effectiveness of various alternative standards (Teknekron, 1978). Several emission standard

TABLE 6-1

IMPACTS ON REGIONAL PRODUCTION OF COAL

Region	Regional Production of Coal, Millions of Tons Existing Standard 1975	1985	1990	1995	Revised Standard[a] 1990
Northern Appalachia	179	172	305	223	258
Central and Southern Appalachia	218	236	237	241	218
Midwest and Central	151	243	298	331	364
Northern Great Plains	55	424	810	1160	650
Rest of West	44	143	218	247	220
Total	647	1218	1768	2201	1711
Western Coal to East	21	206	455	601	298

[a] 90 percent reduction of potential emissions.

Source: ICF, Inc., 1978.

alternatives were considered: 90 percent removal of potential SO_2 emissions, 80 percent removal of potential SO_2 emissions, and an emission limitation of 220 ng/J (0.5 lb $SO_2/10^6$ Btu). To account for uncertainty in future energy projections a moderate electrical demand growth reflecting future conservation measures and a high demand growth were assumed. The resulting estimated national SO_2 emissions for the alternative standards and the two growth rates are shown in Figures 6-1 and 6-2 and quantified for the years 1985, 1990, 1995, and 2000 in Tables 6-2 and 6-3.

Salient features of these data can be summarized as follows:

- The maximum reduction in national SO_2 emissions from the level projected with the current NSPS is projected to be 35 percent, obtained in the year 2000 under high growth conditions with a 90 percent removal revised standard. However, the maximum impact will occur after the year 2000 when more of the older plants will be closing down.

- Relaxing the SO_2 removal requirement from 90 to 80 percent reduces the maximum projected reduction to 21 percent.

- Assuming a moderate electricity demand growth rate after 1985, the maximum projected reduction in SO_2 emissions in 2000 at the national level is 20 percent.

- More stringent new source standards have a more substantial impact at the regional level: emission of SO_2 in the Mountain and West Central states will be reduced by 49 and 39 percent, respectively, by 1990 assuming the 90 percent removal requirement.

- Given the coal sulfur levels used in this analysis, the amount of SO_2 emitted under the 80 percent removal standard and the 215 ng/J (0.5 lb/10^6 Btu) standard are nearly the same in most regions. Nationally, emissions differ by a maximum of 4 percent. In the Mountain states, where relatively low sulfur coals are used, the 80 percent removal requirement further reduces emissions by about 30 percent in 2000.

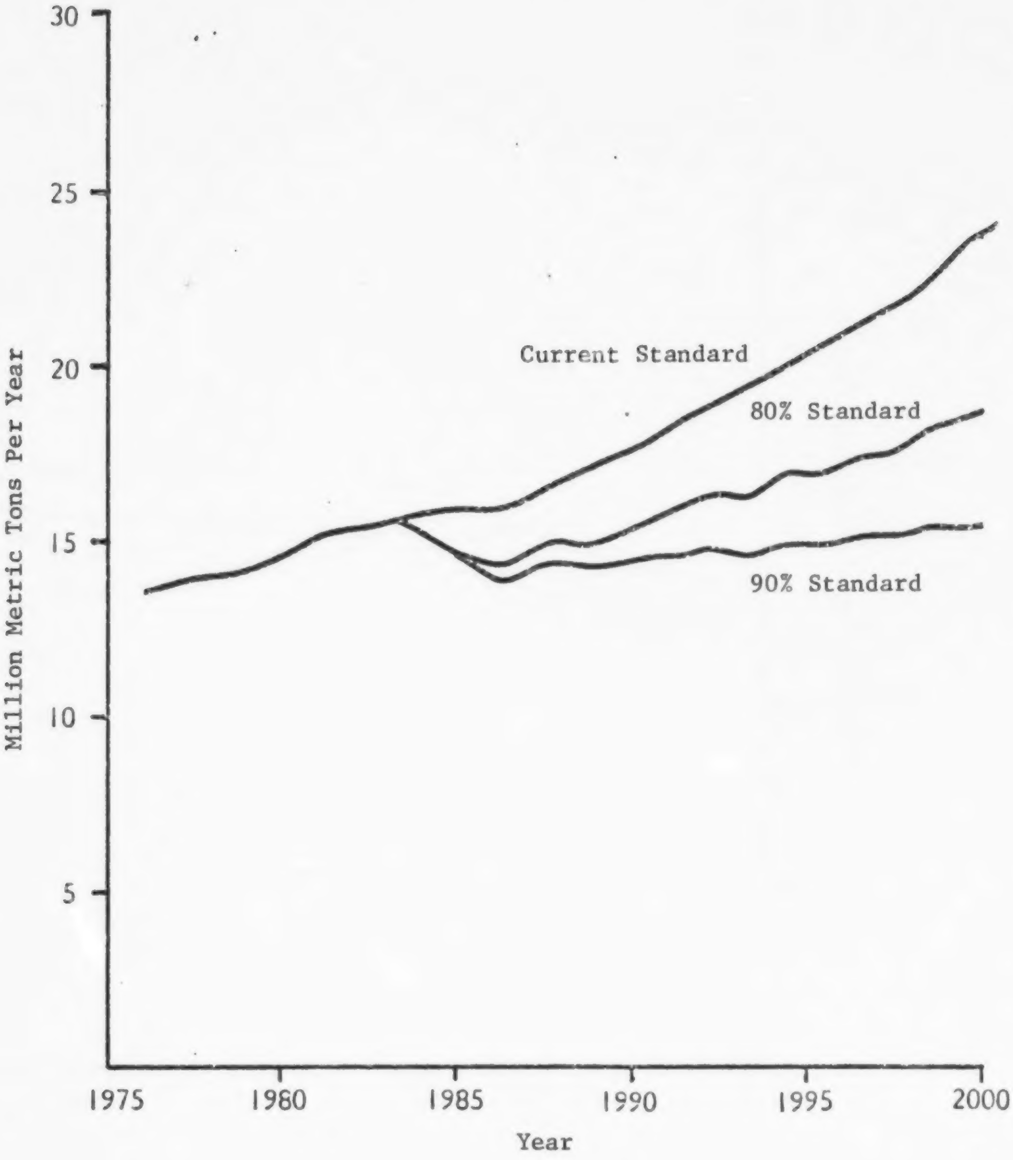


FIGURE 6-1

NATIONAL POWER-PLANT SO_2 EMISSIONS UNDER ALTERNATIVE CONTROL SCENARIOS, HIGH GROWTH

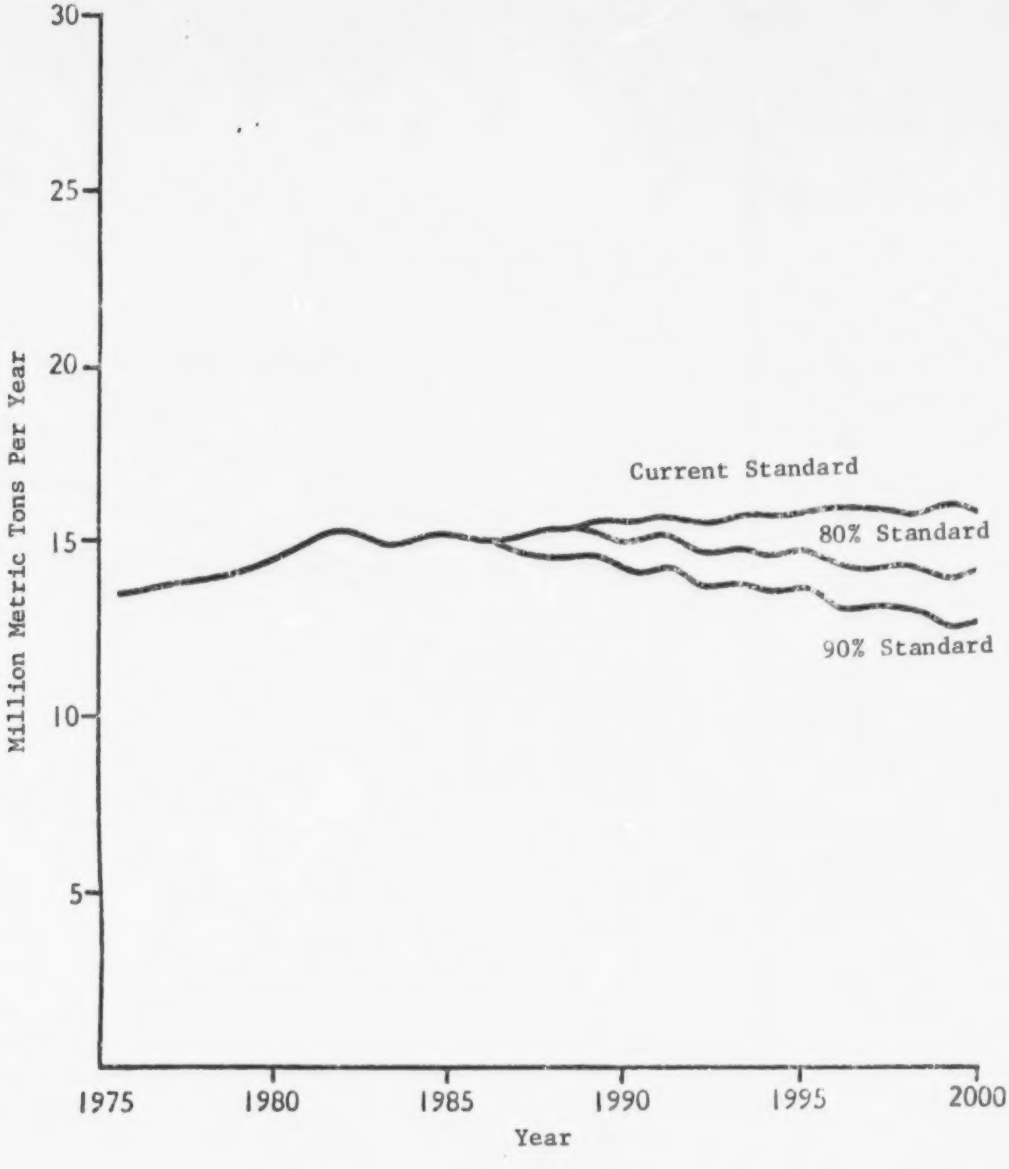


FIGURE 6-2

NATIONAL POWER-PLANT SO_2 EMISSIONS
UNDER ALTERNATIVE CONTROL SCENARIOS, MODERATE GROWTH

TABLE 6-2

REGIONAL AND NATIONAL POWER-PLANT SO_2 EMISSIONS ASSUMING HIGH GROWTH

(Million metric tons per year)

Region	1985	1990	1995	2000
Current Standard				
NE	0.25	0.26	0.32	0.44
MA	1.67	1.62	1.72	1.87
SA	4.04	4.19	4.67	5.18
ENC	4.29	4.75	5.45	6.14
ESC	2.43	2.28	2.26	2.44
WNC	1.56	1.63	1.93	2.29
WSC	0.94	1.84	2.71	3.49
NM	0.07	0.14	0.28	0.42
SM	0.23	0.31	0.38	0.56
PA	0.32	0.43	0.60	0.90
National	15.9	17.5	20.3	23.8
80% Standard				
NE	0.24	0.24	0.29	0.38
MA	0.00	1.67	1.97	2.16
SA	3.75	3.96	4.04	4.09
ENC	3.66	4.11	4.78	5.56
ESC	2.40	2.30	2.25	2.51
WNC	1.30	1.34	1.65	1.91
WSC	0.75	0.98	1.22	1.44
NM	0.06	0.09	0.12	0.15
SM	0.20	0.20	0.21	0.24
PA	0.26	0.26	0.26	0.32
National	14.3	15.2	16.8	18.8
90% Standard				
NE	0.23	0.20	0.22	0.24
MA	1.65	1.54	1.59	1.60
SA	3.70	3.62	3.46	3.27
ENC	3.60	3.91	4.29	4.67
ESC	2.39	2.27	2.37	2.47
WNC	1.30	1.31	1.59	1.75
WSC	0.73	0.82	0.90	0.98
NM	0.06	0.07	0.08	0.09
SM	0.19	0.17	0.15	0.15
PA	0.25	0.24	0.22	0.24
National	14.1	14.2	14.9	15.5

Source: Teknekron

TABLE 6-3

REGIONAL AND NATIONAL POWER-PLANT SO_2 EMISSIONS ASSUMING MODERATE GROWTH

(Million metric tons per year)

Region	1976	1985	1990	1995	2000
Current Standard					
NE	0.23	0.25	0.31	0.25	0.26
MA	2.06	1.70	1.66	1.62	1.69
SA	3.09	3.62	3.53	3.73	3.80
ENC	3.50	3.96	3.79	3.69	3.61
ESC	2.64	2.44	2.38	2.28	2.00
WNC	1.32	1.61	1.58	1.70	1.83
WSC	0.11	0.95	1.52	1.73	1.91
NM	0.12	0.09	0.13	0.18	0.24
SM	0.34	0.23	0.30	0.28	0.28
PA	0.20	0.31	0.31	0.33	0.29
National	13.6	15.2	15.5	15.8	15.9
80% Standard					
NE		0.24	0.29	0.22	0.22
MA		1.68	1.59	1.52	1.53
SA		3.93	3.82	3.82	3.68
ENC		4.36	3.96	3.64	3.22
ESC		2.44	2.39	2.28	2.05
WNC		1.43	1.37	1.53	1.76
WSC		0.78	1.02	1.12	1.14
NM		0.07	0.07	0.09	0.11
SM		0.20	0.20	0.20	0.18
PA		0.27	0.25	0.21	0.16
National		15.4	15.0	14.3	14.1
90% Standard					
NE		0.23	0.25	0.18	0.18
MA		1.65	1.49	1.36	1.29
SA		3.88	3.60	3.49	3.24
ENC		4.30	3.90	3.58	3.17
ESC		2.44	2.35	2.25	2.00
WNC		1.43	1.35	1.49	1.69
WSC		0.74	0.84	0.79	0.76
NM		0.06	0.05	0.06	0.07
SM		0.19	0.17	0.16	0.13
PA		0.26	0.22	0.19	0.13
National		15.2	14.3	13.6	12.7

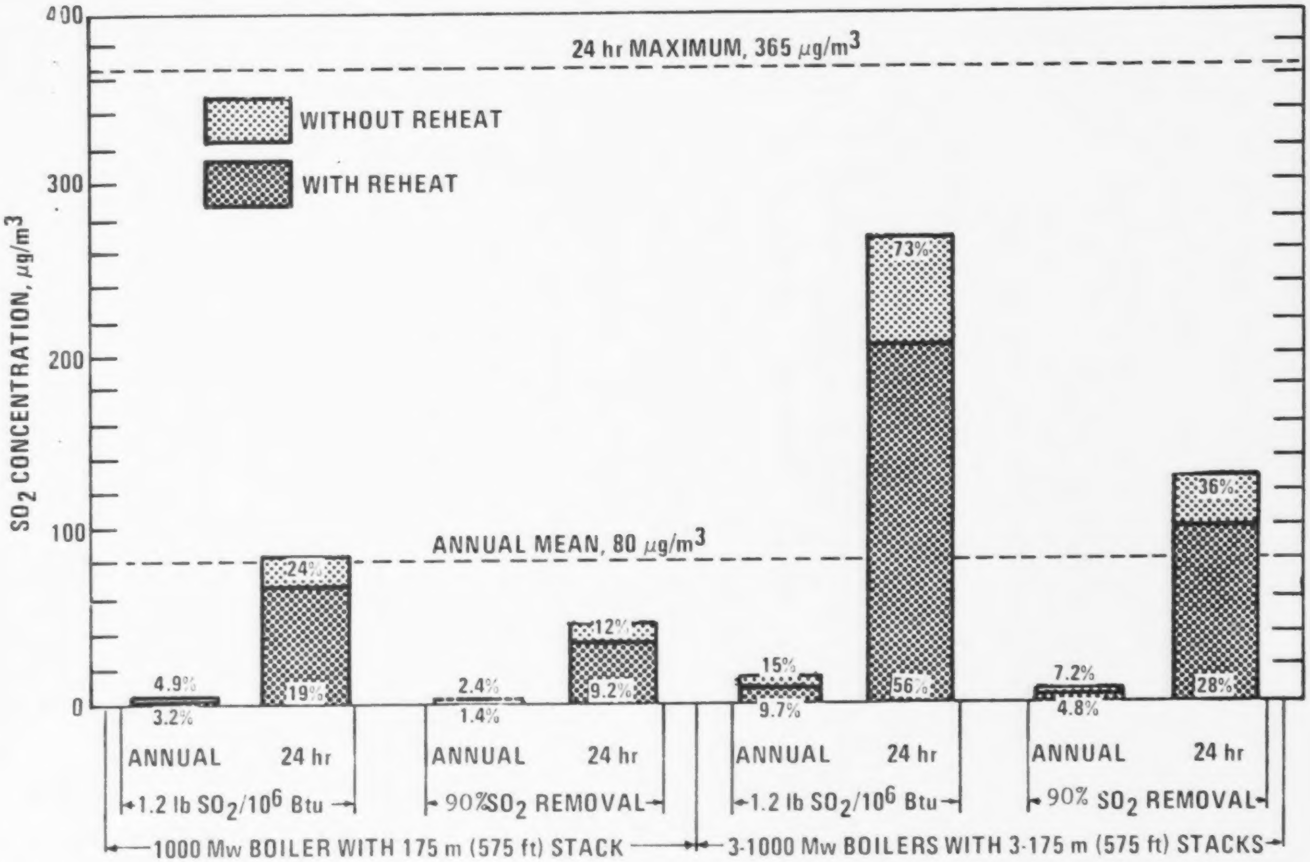
Source: Teknekron

6.2.2 Ambient SO_2 Concentrations

Atmospheric dispersion modeling for several broad geographic meteorological conditions and power plant size combinations was performed to estimate ambient air quality. For current standard of 520 ng/J (1.2 lb $SO_2/10^6$ Btu) the predicted ambient air quality near a power plant was discussed in Section 5.3.

Since SO_2 has a relatively low reaction rate and the dispersion pattern due to emissions is independent of the SO_2 emission rate, a change in the standard would cause a directly proportional change in the ambient air quality concentration if current state parameters are not changed (i.e. reheat). Therefore, the effect of changing the 520 ng/J (1.2 lb/10^6 Btu) emission standard to 220 ng/J (0.5 lb/10^6 Btu) all other factors remaining the same would be to reduce all values (see Table 5-8) by 58 percent. Since SO_2 emissions corresponding to a 90 percent reduction standard are lower than emissions for 220 ng/J (0.5 lb/10^6 Btu) standard, ambient SO_2 concentrations would be lower for a 90 percent standard.

Figure 6-3 illustrates the potential reduction in local ambient air quality with a 85 percent SO_2 emission reduction standard for a single 1,000-MWe plant and for a grouping of three 100-MWe boilers with three stacks. The effectiveness of reheat as a means of increasing plume height, thereby causing greater dispersion and reduced ground concentrations, is evident in Figure 6-3. Reductions



Using 3.5 percent sulfur coal.

Source: EPA, 1977a; 1977b.

FIGURE 6-3

PRIMARY AMBIENT AIR QUALITY STANDARDS
(Eastern Plant)

of 20 to 25 percent in local concentration would occur with reheated stack exhausts compared with no FGD systems without reheat. Given a pristine background concentration, the 90 percent SO_2 emission reduction standard would result in an approximate halving of the 24-hour and annual local ambient air quality concentration for either case (one or three utility boilers). In areas where SO_2 background concentrations are not negligible, Figure 6-2 can be interpreted to indicate that the probability of a 24-hour primary standard violations for a given background concentration is greatly reduced under the 90 percent standard. The probability of annual standard violations is relatively insensitive to the revision of the standard.

6.3 Water

6.3.1 Water Quantity

The various types of FGD systems differ in the amount of water each consumes in order to scrub an equivalent stream of flue gas. Assuming 90 percent removal of sulfur dioxide the water required for five types of FGD systems (lime, limestone, Wellman-Lord, magnesia slurry, and double alkali) has been calculated for a number of different size generating plants, Table 6-4. Comparing water consumption of FGD systems for 520 ng/J (1.2 lb/10^6 Btu) SO_2 emission standard (see Table 5-12) and for the 90 percent SO_2 removal shows that the water consumption for the same size FGD system is approximately the same for these two SO_2 emission limitations. With

TABLE 6-4

MODEL PLANT SYSTEM WATER REQUIREMENTS

Case	Power Plant Capacity MW	SO_x Control Strategy	% Sulfur Removal	System #3 Power Plant Makeup Water Requirement m^3/s	(gpm)	SO_x Control Strategy Makeup Water Requirement m^3/s	(gpm)	Total Model System Makeup Water Requirement m^3/s	(gpm)
41	1000	Lime	90	0.76	(12,000)	0.070	(1,100)	0.82	(13,000)
42	1000	Limestone	90	0.76	(12,000)	0.070	(1,100)	0.82	(13,000)
43	1000	Wellman-Lord	90	0.76	(12,000)	0.095	(1,500)	0.88	(14,000)
44	1000	Magnesium Oxide	90	0.76	(12,000)	0.088	(1,400)	0.82	(13,000)
45	1000	Double Alkali	90	0.76	(12,000)	0.076	(1,200)	0.82	(13,000)
46	500	Lime	90	0.38	(6,100)	0.035	(550)	0.42	(6,600)
47	500	Limestone	90	0.38	(6,100)	0.035	(550)	0.42	(6,600)
48	500	Wellman-Lord	90	0.38	(6,100)	0.049	(770)	0.44	(6,900)
49	500	Magnesium Oxide	90	0.38	(6,100)	0.044	(700)	0.43	(6,800)
50	500	Double Alkali	90	0.38	(6,100)	0.038	(610)	0.42	(6,700)
51	100	Lime	90	0.076	(1,200)	0.0069	(110)	0.082	(1,300)
52	100	Limestone	90	0.076	(1,200)	0.0069	(110)	0.082	(1,300)
53	100	Wellman-Lord	90	0.076	(1,200)	0.0095	(150)	0.088	(1,400)
54	100	Magnesium Oxide	90	0.076	(1,200)	0.0088	(140)	0.082	(1,300)
55	100	Double Alkali	90	0.076	(1,200)	0.0076	(120)	0.082	(1,300)
56	25	Lime	90	0.020	(310)	0.0017	(27)	0.021	(340)
57	25	Limestone	90	0.020	(310)	0.0018	(28)	0.021	(340)
58	25	Wellman-Lord	90	0.020	(310)	0.0024	(38)	0.022	(350)
59	25	Magnesium Oxide	90	0.020	(310)	0.0022	(35)	0.021	(340)
60	25	Double Alkali	90	0.020	(310)	0.0019	(30)	0.021	(340)

The type of coal burned contained 3.5% S; 28 MJ/kg (12000 Btu/lb); 12% ash; 2.6% H_2O.

Source: Radian, 1977c.

90 percent SO_2 removal the water consumption increases proportionally with the size of the plant and represents approximately ten precent of the plant make-up water requirement.

A 500-MW power plant that burns 0.8 percent sulfur coal having a heating value of 19 MJ/kg (8,000 Btu/lb) and that uses a limestone scrubber to meet the 220 ng/J emission limitation would consume 0.032 m^3/s (500 gm of water). Whereas it is possible to meet the present standard without using an FGD systems by burning low sulfur western coal, compliance with the 90 percent SO_2 removal and the 220 ng/J (0.5 lb $SO_2/10^6$ Btu) standard will require the use of scrubbers. Thus, there would be consumption of water by FGD systems to meet revised SO_2 emission standards at some plants (mostly those in the West) where none was required with the existing SO_2 emission standard.

Projections of the consumption of water by FGD systems on a regional basis were made for a 90 percent removal of sulfur from flue gas for both high and moderate growth (Table 6-5). A comparison of regional water consumption of FGD systems for the present SO_2 emission limitations (see Table 5-14) and for the 90 percent removal standard shows that substantially more water would be required in most regions for increased removal of sulfur from flue gas with either high or moderate growth. Also, the amount of water required nationally and for most regions would increase with time to the year 2000.

TABLE 6-5

WATER CONSUMED BY FGD SYSTEMS

(Thousand acre-feet per year)[a]

REGION	1990	1995	2000
a. Moderate-Growth Rate (90 Percent SO_2 Removal)			
NE	3.83	4.44	5.37
MA	20.5	26.9	36.2
SA	34.0	52.4	65.2
ENC	16.3	15.6	13.6
ESC	4.49	5.56	6.09
WNC	5.78	10.7	19.1
WSC	58.4	89.6	108.
NM	11.2	15.9	19.5
SM	33.0	30.1	31.2
PA	7.82	9.79	9.49
Nation	195.	261.	314.
b. High-Growth Rate (90 Percent SO_2 Removal)			
NE	4.40	7.62	15.0
MA	32.2	60.8	85.2
SA	51.8	83.6	116.
ENC	30.4	66.6	109.
ESC	3.17	10.7	24.5
WNC	10.9	28.4	53.0
WSC	75.1	141.	209.
NM	16.1	25.8	34.3
SM	30.6	37.6	46.6
PA	18.0	29.7	58.3
Nation	273.	492.	751.

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[a] The metric units are not used because of the established convention of using acre-feet for water supply data; 1 acre-foot=1,234 cubic meters.

Source: Teknekron, 1978.

6.3.2 Water Quality

FGD systems need not have effluent discharges that would impact existing water existing water quality. However, if any water were discharged into contiguous streams, it would have to meet water quality standards. Such discharges may occur when the system has to be purged. These purges are necessitated by process problems of (1) water imbalances, (2) changes in operation from design conditions, (3) catastrophic blowdown of the system to prevent scaling, and (4) operator errors of various kinds. The composition of the purge liquid is as follows: calcium sulfite, calcium sulfate, sodium chloride and trace elements in lime and limestone FGD purge liquid; sodium sulfite, sodium sulfate and sodium chloride in the double alkali purge liquid; and silica, ferric oxide, aluminum chloride and sulfate ions, calcium oxide, calcium sulfate and calcium chloride, magnesium sulfite, magnesium sulfate, and trace elements of the magnesia slurry FGD purge liquid. The purge liquids can be treated and the water can be returned to the system.

6.4 Land Use

6.4.1 Land Use for the Physical Plant

The land upon which the scrubber and the storage facility for the absorbent are constructed would necessarily be close to the generating plant buildings. Construction of a power plant would usually cause adjacent lands to be devoid of most of the vegetation and animals typical of the region. Therefore, construction of FGD on land near the generating plant buildings would not result in any additional ecological impact. It is likely that this land would not have any other commercial or agricultural value while the generating plant is operating. Presumably, the entrire plant site, including that used for flue gas desulfurization, would be available for commercial use or left for invasion by indigenous flora and fauna when the plant is decommissioned.

6.4.2 Land Used for Solid Waste Disposal

The land used to dispose of solid wastes generated by limestone, lime and double alkali fuel gas desulfurization systems would be lost to other commercial or agricultural purposes as long as the disposal site is operated. For a 500-MW unit coal-fired plant burning eastern and western coal, projected use of disposal site land for limestone scrubber waste for all of the installed generating capacity (for the years 1978 through 1998) would be slightly greater if the 90 percent emission limitation were adopted than if the present standard of 520 ng/J (1.2 lb $SO_2/10^6$ Btu) remained in effect (see Tables 5-16 and 6-6). The amount of land predicted to be required if the standard were revised to 220 ng/J (0.5 lb $SO_2/10^6$ Btu) for the years 1978 through 1998 is shown in Table 6-7. The apparent paradox that the 220 ng/J limit would result not only in lower emissions but also in less total waste and lower land requirements than either of the other two SO_2 emission limitations is the result of the assumption that coal washing of eastern coal is used to remove 40 percent of its

TABLE 6-6

PROJECTED LAND REQUIREMENTS FOR COAL-FIRED ELECTRIC GENERATING PLANTS - 90 PERCENT SCRUBBING

YEAR	ANNUAL INSTALLED GENERATING CAPACITY, MW	NUMBER OF EQUIV PLANTS	EASTERN COAL			WESTERN COAL			TOTAL ANNUAL REQUIREMENTS		
			DRY WASTE, tons x 10^6	ANNUAL ACRES	TOTAL ANNUAL ACREAGE REQUIRED FOR 30 yr	DRY WASTE, tons x 10^6	ACRES	TOTAL ANNUAL ACREAGE REQUIRED FOR 30 yr	DRY WASTE tons x 10^6	ACRES	ACREAGE REQUIRED FOR 30 yr
1978	15,303	30.6	4.642	201	6,017	1.009	43.5	1,309	5.651	245	7,3[illegible]2
1979	15,544	31.1	4.355	188	11,662	1.172	50.6	2,823	11.179	483	14,485
1980	21,101	42.2	5.761	249	19,140	2.271	98.0	5,763	19.211	829	24,903
1981	15,639	31.3	4.270	184	24,660	1.683	72.7	7,944	25.164	1087	32,604
1982	17,854	35.7	4.874	210	30,960	1.921	83.0	10,434	31.959	1380	41,394
1983	18,079	36.2	4.936	213	37,350	1.946	84.0	12,954	38.841	1677	50,304
1984	16,319	32.6	4.455	192	43,110	1.757	75.8	15,228	45.054	1945	58,338
1985	19,519	39.0	5.329	230	50,010	2.101	90.7	17,949	52.484	2265	67,959
1986	18,000	36.0	4.914	212	56,370	1.938	83.6	20,457	59.336	2561	76,827
1987	17,000	34.0	4.641	200	62,370	1.830	79.0	22,827	65.807	2840	85,197
1988	20,000	40.0	5.460	236	69,450	2.153	92.9	25,614	73.421	3169	95,064
1989	19,000	38.0	5.187	224	76,170	2.045	88.3	28,263	80.653	3481	104,433
1990	21,000	42.0	5.733	247	83,580	2.260	97.6	31,191	88.647	3826	114,771
1991	28,000	56.0	7.645	330	93,480	3.014	130.1	35,094	99.305	4286	128,574
1992	22,000	44.0	6.006	259	101,250	2.368	102.2	38,160	107.680	4647	139,410
1993	24,000	48.0	6.552	283	109,740	2.583	111.5	41,505	116.815	5012	151,245
1994	30,000	60.0	8.191	353	120,330	3.229	139.4	45,687	128.235	5544	166,017
1995	24,000	48.0	6.552	283	128,820	2.583	111.5	49,032	137.370	5928	177,852
1996	30,000	60.0	8.191	353	139,410	3.229	139.4	53,214	148.790	6421	192,624
1997	30,000	60.0	8.191	353	150,000	3.229	139.4	57,396	160.209	6914	207,396
1998	33,000	66.0	9.010	389	161,670	3.552	153.3	61,995	172.771	7456	223,665

Source: Aerospace, 1977.

TABLE 6-7

PROJECTED LAND REQUIREMENTS FOR COAL-FIRED ELECTRIC GENERATING PLANTS - 220 NG/J (0.5 LB $SO_2/10^6$ Btu)

YEAR	ANNUAL INSTALLED GENERATING CAPACITY, MW	NUMBER OF EQUIV PLANTS	EASTERN COAL			WESTERN COAL			TOTAL ANNUAL REQUIREMENTS		
			DRY WASTE, tons x 10^6	ACRES	TOTAL ANNUAL ACREAGE REQUIRED FOR 30 yr	DRY WASTE, tons x 10^6	ACRES	TOTAL ACREAGE REQUIRED FOR 30 yr	DRY WASTE, tons x 10^6	ACRES	ACREAGE REQUIRED FOR 30 yr
1978	15,303	30.6	4.643	201	6,019	1.009	44	1,307	5.652	245	7,326
1979	15,544	31.1	4.355	188	11,663	1.172	51	2,826	11.179	483	14,488
1980	21,101	42.2	3.196	138	15,802	2.127	92	5,579	16.503	713	21,381
1981	15,639	31.3	2.369	102	18,871	1.576	68	7,620	20.447	883	26,491
1982	17,854	35.7	2.704	117	22,375	1.800	78	9,950	24.952	1078	32,325
1983	18,079	36.2	2.738	118	25,922	1.872	79	12,309	29.512	1274	38,231
1984	16,319	32.6	2.472	107	29,124	1.645	71	14,439	33.630	1452	43,563
1985	19,519	39.0	2.957	128	32,954	1.968	85	16,986	38.554	1664	49,940
1986	18,000	36.0	2.726	118	36,486	1.814	79	19,335	43.094	1861	55,821
1987	17,000	34.0	2.575	111	39,821	1.714	74	21,554	47.383	2045	61,375
1988	20,000	40.0	3.029	131	43,745	2.016	87	24,164	52.428	2263	67,909
1989	19,000	38.0	2.878	124	47,473	1.915	83	26,643	57.221	2470	74,116
1990	21,000	42.0	3.181	137	51,594	2.117	91	29,384	62.519	2699	80,978
1991	28,000	56.0	4.241	183	57,088	2.822	122	33,038	69.582	3004	90,126
1992	22,000	44.0	3.332	144	61,405	2.218	96	35,909	75.133	3244	97,314
1993	24,000	48.0	3,635	157	66,114	2.419	104	39,041	81.187	3505	105,155
1994	30,000	60.0	4.544	196	72,000	3.024	131	42,956	88.755	3832	114,956
1995	24,000	48.0	3.635	157	76,709	2.419	104	46,088	94.809	4093	122,797
1996	30,000	60.0	4.544	196	82,596	3.024	131	50,003	102.378	4120	132,600
1997	30,000	60.0	4.544	196	88,482	3.024	131	53,918	109.946	4746	142,400
1998	33,000	66.0	4.999	216	94,957	3.326	144	58,224	118.271	5106	153,181

Source: Aerospace, 1977.

sulfur (Aerospsace, 1977). The coupling of coal washing with a non-regenerable scrubber system reduces the amount of land required for disposal of solid wastes at the power plant since some portion of the solid waste is disposed of at the coal washing site. The land requirement attributed only to desulfurization wastes for any of the alternative standards discussed is substantially less than that shown in the tables, since the data presented for total solid wastes includes the contributions of fly ash and solid wastes produced by the particulate removal systems.

6.5 Ecology

6.5.1 Ecology at the Physical Plant

An ecosystem that exists on the land prior to construction and operation of a power plant would be destroyed at the time of construction with some favored species of plants eventually replacing indigenous varieties. Continued minor encroachment of wild varieties of plants and animals would occur but could be controlled. As a result, the ecology at the site of an existing power plant would be simpler both qualitatively and quantitatively than the one it replaced. The use of ornamental species of plants for aesthetic purposes and erosion control is a well developed art applied to different portions of land used in power generation. However, any attempt at growing plants on ash and flue gas solid wastes must be characterized as experimental. There are some apparent successes in the use of flue gas solid wastes as fertilizers, such as its use with the growing of rye grass by TVA.

6.5.2 Ecology at the Disposal Site

The exact nature of the ecological, commercial, or agricultural losses resulting from solid waste disposal would be site specific, but virtually all flora and fauna would be removed from this land. Whether or not these losses can be confined to just the acreage used for a disposal dump is another site specific problem that depends upon many factors in the ambient environment, how well the disposal dump is managed, and whether ecologically sensitive areas such as animal migration paths or nesting grounds exist. It is clear that many of the negative ecological effects and problems with regional development resulting from the solid waste disposal site could be greatly minimized if proper consideration is given to ecology and regional planning in a site selection study and if a good disposal site management plan is adopted. Similar basic problems can be expected to arise if the disposal site is in the ocean or some large body of water; however, solid waste disposal sites in large bodies of water appear to be less ecologically promising because of the difficulty in stabilizing the solid wastes in a fluid environment. If the solid waste disposal site is located in a rock quarry or mine, there would be an opportunity for improving a highly stressed environmental condition. This approach to the disposal of solid waste could potentially restore some of the ecology of the area and reestablish the original contour of the land. Also, more valuable land, which has been less disturbed ecologically, would not have to be used for a solid waste disposal site. A good dump management program as well as proper consideration of the existing environment and its surrounding ecology is still required if the environmental impact is to be minimized.

6.6 Energy Penalties Associated with Alternate Strategies

An analysis similar to that described in Section 5.6 was performed to examine the manner in which various alternative levels of control could affect the energy penalty associated with various control techiques and coal mixes.

Table 6-8 summarizes the calculated energy penalties as a function of plant size, coal sulfur content, and SO_2 removal level (current standard versus 90 percent removal). The values in the table are normalized to indicate the energy penalty per kilowatt generated. The penalties as a percentage of the power plant net heat rates (total plant heat rate divided by the generating capacity) are shown in parenthesis.

Three points are of particular interest. First, 90 percent removal results in about a 10 percent higher energy use with respect to both nonregenerable and regenerable processes for a given coal sulfur content. Second, doubling the sulfur content of the coal from 3.5 percent to 7.0 percent causes about a 60 percent increase in the energy penalty using the MgO process and a doubling of the energy penalty using the Well-Lord/ Allied process. (The 7.0 percent

TABLE 6-8

ENERGY PENALTIES FOR MODEL SO_2 CONTROL SYSTEMS

	Coal	SO_2 Control Level	Control Technique	SO_2 Control Penalty, J/kW-s (% of energy input to uncontrolled plant) 25 MW	100 MW	500 MW	1000 MW
NON-REGENERABLE	3.5% Sulfur; 27.9 MJ/kg	0.52 g SO_2/MJ	FGD-Lime	90 (3.3)	90 (3.3)	80 (3.0)	80 (3.1)
	3.5% Sulfur; 27.9 MJ/kg	90% removal	FGD-Lime	90 (3.3)	90 (3.3)	90 (3.4)	90 (3.5)
	7.0% Sulfur; 27.9 MJ/kg	90% removal	FGD-Lime	100 (3.7)	100 (3.7)	100 (3.8)	90 (3.5)
	3.5% Sulfur; 27.9 MJ/kg	0.52 g SO_2/MJ	FGD-Limestone	90 (3.3)	90 (3.3)	90 (3.4)	80 (3.1)
	3.5% Sulfur; 27.9 MJ/kg	90% removal	FGD-Limestone	100 (3.7)	100 (3.7)	100 (3.8)	90 (3.5)
	7.0% Sulfur; 27.9 MJ/kg	90% removal	FGD-Limestone	120 (4.4)	120 (4.4)	110 (4.2)	110 (4.3)
	3.5% Sulfur; 27.9 MJ/kg	0.52 g SO_2/MJ	D-A FGD	80 (2.9)	80 (3.0)	80 (3.0)	80 (3.1)
	3.5% Sulfur; 27.9 MJ/kg	90% removal	D-A FGD	80 (2.9)	80 (3.0)	80 (3.0)	80 (3.1)
	7.0% Sulfur; 27.9 MJ/kg	90% removal	D-A FGD	90 (3.3)	90 (3.3)	80 (3.0)	80 (3.1)
REGENERABLE	3.5% Sulfur; 27.9 MJ/kg	0.52 g SO_2/MJ	MgO FGD	150 (5.5)	150 (5.5)	140 (5.3)	130 (5.1)
	3.5% Sulfur; 27.9 MJ/kg	90% removal	MgO FGD	160 (5.9)	160 (5.9)	160 (6.1)	150 (5.9)
	7.0% Sulfur, 27.9 MJ/kg	90% removal	MgO FGD	260 (9.6)	260 (9.6)	250 (9.5)	240 (9.4)
	3.5% Sulfur; 27.9 MJ/kg	0.52 g SO_2/MJ	W-L/A FGD	320 (11.8)	320 (11.8)	310 (11.7)	290 (11.4)
	3.5% Sulfur; 27.9 MJ/kg	90% removal	W-L/A FGD	360 (13.2)	360 (13.3)	350 (13.3)	340 (13.3)
	7.0% Sulfur; 27.9 MJ/kg	90% removal	W-L/A FGD	710 (26.1)	700 (25.8)	680 (25.8)	660 (25.9)
	2.2% Sulfur; 29.2 MJ/kg	0.52 g SO_2/MJ	Coal cleaning/FGD-Lime	NE	NE	260 (9.8)	NE
	2.2% Sulfur; 29.2 MJ/kg	0.22 g SO_2/MJ	Coal cleaning/FGD-Lime	270 (9.9)	NE	260 (9.8)	NE
	4.4% Sulfur; 29.2 MJ/kg	0.22 g SO_2/MJ	Coal cleaning/FGD-Lime	280 (10.3)	NE	270 (10.2)	NE
	2.2% Sulfur; 29.2 MJ/kg	0.52 g SO_2/MJ	Coal clean/FGD-Limestone	NE	NE	260 (9.8)	NE
	2.2% Sulfur; 29.2 MJ/kg	0.22 g SO_2/MJ	Coal clean/FGD-Limestone	280 (10.3)	NE	270 (10.2	NE
	4.4% Sulfur; 29.2 MJ/kg	0.22 g SO_2/MJ	Coal clean/FGD-Limestone	300 (11.0)	NE	290 (11.0)	NE
	0.4% Sulfur; 20.9 MJ/kg	Uncontrolled	Western coal	170 (6.2)	NE	170 (6.4)	NE
	0.6% Sulfur; 25.6 MJ/kg	Uncontrolled	Western coal	150 (5.5)	NE	140 (5.3)	NE

NE - not examined

Uncontrolled power plant net heat rates:

- 25 MW - 2720 J/kW-s
- 100 MW - 2710 J/kW-s
- 500 MW - 2640 J/kW-s
- 1000 MW - 2550 J/kW-s

sulfur coal is an extreme worst case example. Most coal would be in the 2 to 3 percent sulfur range with a maximum of 5 percent.) This result is due to the sulfur recovery step associated with these processes. Finally, as indicated in Section 5.6, the various alternatives are relatively independent of plant size when normalized to a per kilowatt-second (KW-S) basis.

Using the methodology described in Section 5.6.3 projections of the energy penalty associated with the 80 and 90 percent SO_2 reduction standards were calculated (Teknekron 1978). Table 6-9 gives the results of the projections for the baseline (current standard) case and the two alternative standards in the year 1995. The highest energy impact would occur with the 90 percent removal standard. Compared with the current standard, three times as much energy would be expended for FGD with the moderate energy growth scenario and five times as much with the high energy growth rate if the 90 percent standard were in force.

A second energy impact, which could be significant if a revised standard resulted in large shifts in coal supplies, is the change in the energy consumed in transporting the coal. A shift away from the use of western coal in the Midwest in favor of more local supplies, for example, would be expected to reduce coal transport energy. Results of this impact for the 90 percent control scenarios are shown in Table 6-10.

TABLE 6-9

ENERGY CONSUMED BY FGD SYSTEMS IN 1995
(10^9 Megajoules)

Growth Rate	Energy Consumption for FGD	Fraction of Energy for Generation (Percent)
Moderate		
Current standard	187	0.95
80 percent removal	534	2.7
90 percent removal	588	3.0
High		
Current Standard	214	0.71
80 percent removal	548	1.8
90 percent removal	1150	3.8

Source: Teknekron, 1978.

TABLE 6-10

ENERGY CONSUMED IN TRANSPORTING COAL TO ELECTRIC GENERATING PLANTS
(10^9 Megajoules)

	Moderate Growth		High Growth	
Year	Current Standard	90 Percent Removal	Current Standard	90 Percent Removal
1976	100	100	100	100
1990	250	230	370	320
1995	300	250	560	440
2000	350	260	780	580

Source: Teknekron, 1978.

These results show a significant reduction in fuel consumed with imposition of the more stringent controls, due primarily to a shifting of demand away from western coals delivered to states bordering east of the Mississippi River. Note in particular that the energy savings in 1995, 50 x 10^9 MJ (4.7 x 10^{13} Btu) for the moderate growth case and 120 x 10^9 MJ (11.0 x 10^{13} Btu) for the high growth case, serve to offset about 10 percent of the direct FGD energy requirements projected for that year (588 x 10^9 MJ and 1150 x 10^9 MJ for moderate and high growth, respectively).

6.7 Noise

Noise produced by an operating power plant is substantial. An increase in noise at power plants is expected as a result of the operating FGD system, the transporting of the solid waste generated by the FGD to the disposal site, and the operation of the disposal dump. The amount of noise produced by either the power plant or the FGD system would depend upon the type of system, sizes and levels of operation. The extent to which the sound would be perceived by an individual would depend upon many site specific environmental factors, including wind speed, wind direction and topography. The noise produced by an operating FGD system would not significantly contribute to the degradation of the environment of the plant, since noise abatement techniques for power plants are available.

Depending upon the site and the means of transport, noise associated with transporting solid waste to the disposal site may also prove to be a nuisance. Transporting of solid wastes by truck, train or conveyor belts to the disposal site could result in these conveyances passing through small population centers. Thus, people could be affected by the increased noise levels. Also, ecologically sensitive areas such as nesting grounds for birds or animal migration routes could be disturbed by the noise and the barrier the transportation system would present. Transporting solid wastes by pipeline would alleviate the noise problems; however, if the pipeline is not buried, it would still be a potential barrier to animal migration. Noise produced by the operation of the disposal site has potential environmental consequences similar to those produced in the transportation of waste to the disposal site.

6.8 Secondary Impacts

A revision to the NSPS for coal-fired utility boilers is expected to result in secondary impacts affecting the industries, and the populations supported by these industries, which supply and transport, coal, metal, hardware, and chemicals for FGD systems. Changes in demand for eastern and western coals would impact on employment in the coal mining and transportation industries. A revision of the standard would result in increased demand for FGD systems, thereby effecting those industries which provide such systems. Impacts on all thee industries could result in impacts on employment and in other secondary impacts including shifting needs for housing, schools, and medical facilities. Section 7 presents a discussion of some anticipated secondary economic impacts including the effect on the price of electricity to the consumer.

7.0 ECONOMIC IMPACT ANALYSIS

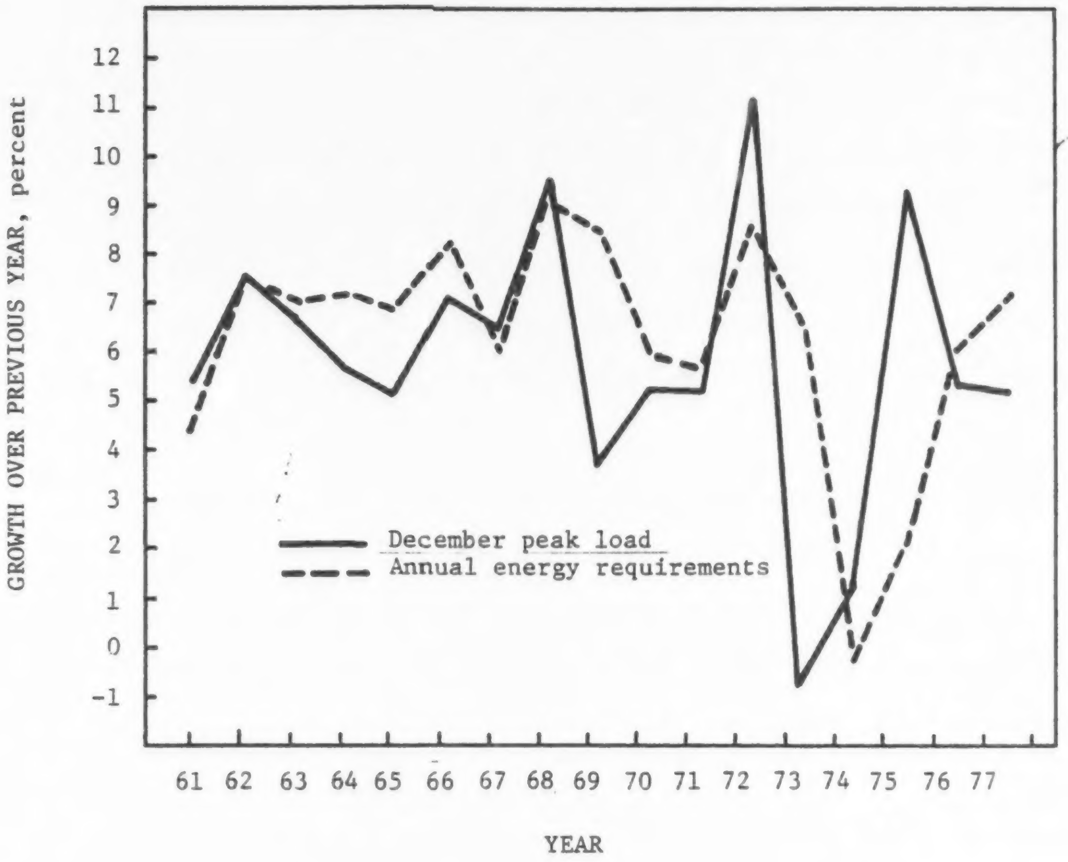
7.1 Industry Profile

7.1.1 General Industry Background

The electric utility industry is by far the predominant user of large coal-fired boilers. Since 1960 over 88 percent of all coal-fired units installed have been for the purpose of generating power for electric utilities. These 404 units have provided some 159,000 MW of capacity, or slightly over 98 percent of the rated megawatts installed.

Significant market perturbations have recently characterized the electric utility industry (Figure 7-1). Following a relatively stable growth rate of 5 to 9 percent per year for both energy and peak-load demand in the 1960s, peak-load demand rose sharply in 1972. The marked drop in demand that occurred in 1973 was ascribed to a worldwide recession and the Arab oil embargo. There was virtually no growth in energy demand in 1974. In 1975 and 1976, however, demand began to rise again but at a rate lower than during the 1961-1972 period.

Plant construction cycles in this industry represent long lead times and immediate responses to changes in demand for power are not possible. Utilities must attempt to predict future needs in order to have time to raise the needed capital and build the plants to meet requirements for electric power. Market perturbations can make it difficult to provide capacity commensurate with future demands. On



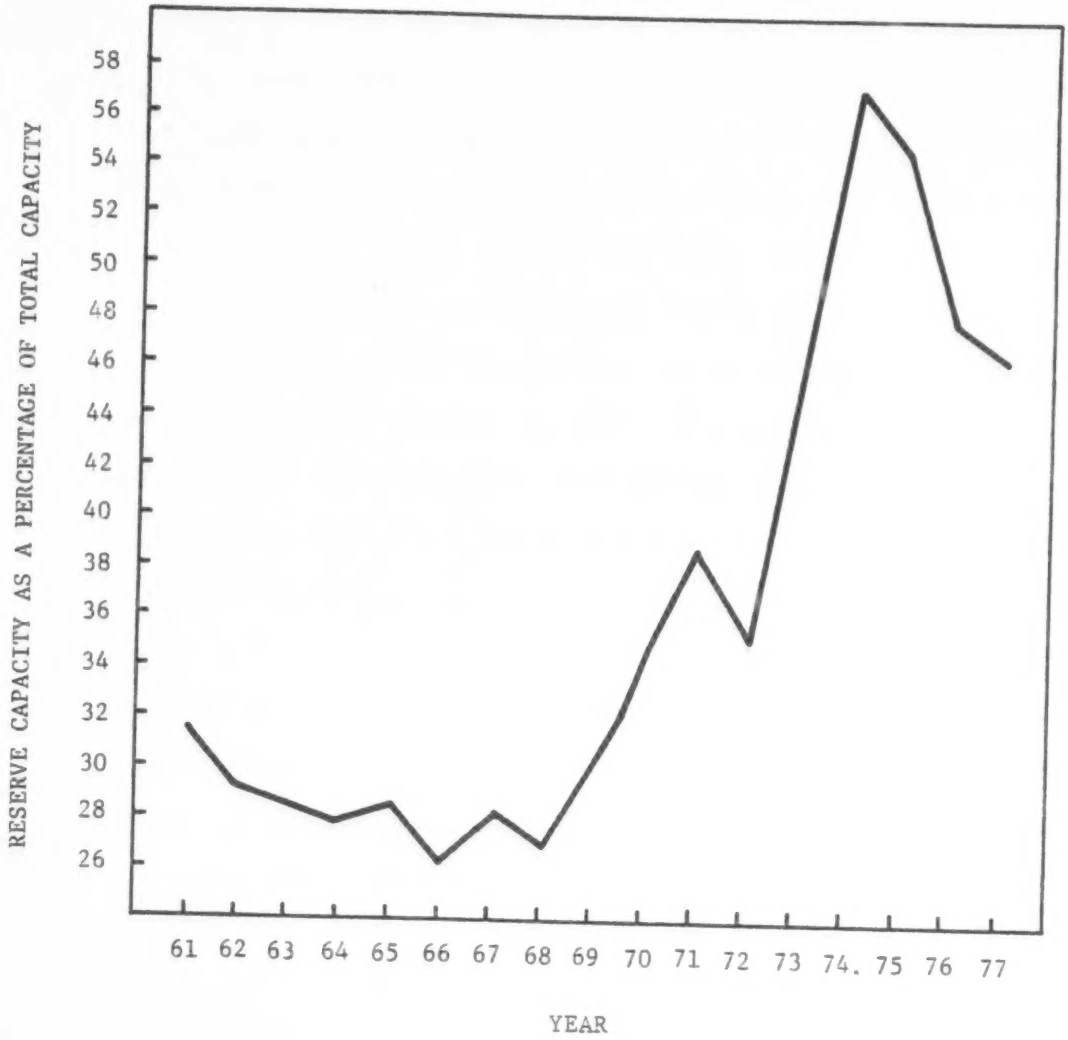
NOTE: Represented by the sum of the individual peak loads of the Regional Council's report to the FPC.

Source: U. S. Federal Power Commission, 1974.

FIGURE 7-1

PERCENTAGE GROWTH RATE OVER PREVIOUS YEAR REPORTED

BY MAJOR U.S. UTILITY SYSTEMS



NOTE: Numbers from all FPC Regional Councils were averaged to get annual representation.

Source: U. S. Federal Power Commission, 1974.

FIGURE 7-2

ANNUAL PEAK RESERVES AS A PERCENTAGE OF TOTAL AVAILABLE CAPACITY the one hand, power needs which turn out to be less than those projected when plant construction is undertaken can result in a temporary excess of reserve capacity. On the other hand, demands which are significantly greater than those planned for earlier cannot be quickly met because of the time needed to raise capital and to build additional facilities. After 1968 reserves in the power industry increased steadily for several years, culminating in 1974 in a high of more than 50 percent excess capacity over winter peak demand (Figure 7-2). Coincidentally, there was a marked drop in the industry's collective system capacity factors (Figure 7-3). Consequently, utilities found themselves with over-committed capital programs at the same time that lower plant utilization was generating less revenue.

Orders for coal-fired boilers decreased significantly in 1975 and 1976 (Table 7-1). Demand rose in 1977, and the market should continue strong with increased annual energy requirements accompanied by pressures on utilities to convert to coal from oil and gas.

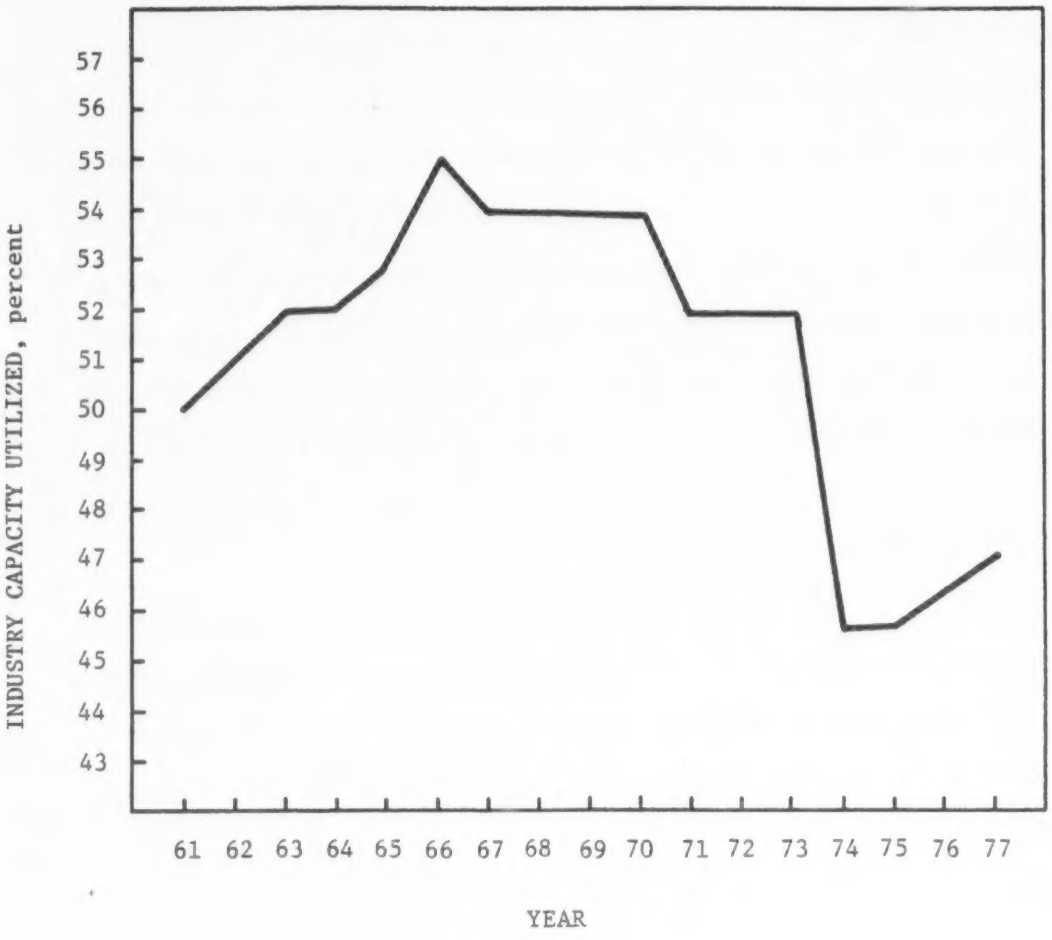
TABLE 7-1

ORDERS FOR COAL-FIRED BOILERS

Year	Boilers Ordered	Megawatt Capacity
1974	69	32,964
1975	22	10,774
1976	13	6,312
1977[a]	20	13,000[b]

[a] Projected

[b] Approximate MWe



NOTE: Capacity factor is calculated by dividing annual energy produced by total dependable energy capacity.

Source: U. S. Federal Power Commission, 1974.

FIGURE 7-3

ANNUAL CAPACITY FACTOR FOR THE MAJOR U.S. ELECTRIC UTILITIES

7.1.2 Predominance of Coal in Electric Power Generation

Historically, coal has provided a greater amount of rated megawattage than any other electric power source. As Table 7-2 shows, in 1976 coal provided 189 GW or about 39 percent of the total rated capacity. During the period 1977-95 coal and nuclear fuel are expected to share the preponderant role in providing additions to the U.S. electric utility system. Two scenarios are projected in Table 7-2. The moderate growth scenario, in which the 1976 generating capacity is slightly more than doubled by 1995, projects coal as providing for some 28 percent of the growth, ranking second to nuclear power. In the high growth scenario, coal would provide about 20 percent of the additions (Teknekron, Inc., 1978).

The growth of electric power from coal is shown from a different perspective in Figure 7-4, which presents the total number of coal-fired units (over 25 MWe) installed or projected between 1960 and 1978. As can be seen, cancellations and delays resulted in a steep drop in 1973; a slow recovery is apparent in the trend since that date.

The average size of coal-fired units installed (and projected) between 1963 and 1978 appears in Figure 7-5. Steady growth in size during the 1960s and early 1970s led to near stabilization at slightly over 500 MW by 1975. The new generation of boilers expected for the 1980s will average over 500 MW and be somewhat larger than those installed 10 years ago.

TABLE 7-2

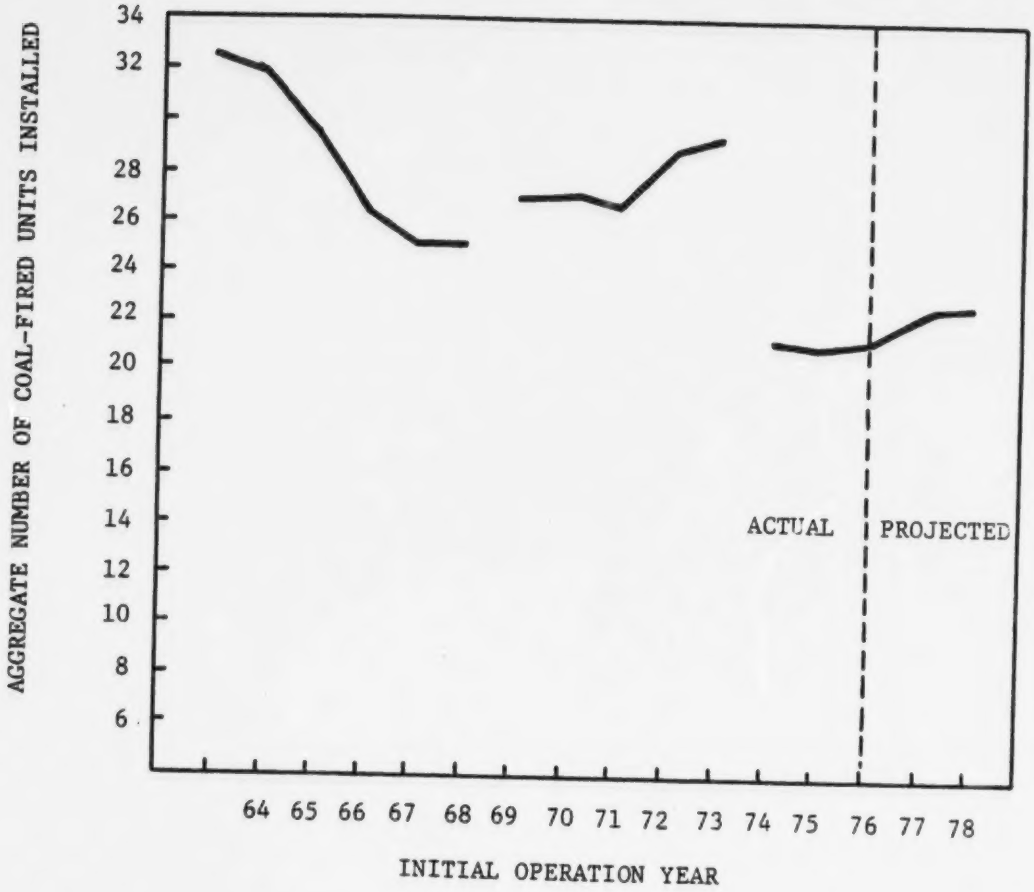
PROJECTED ELECTRIC CAPACITY MIX

(NET CAPABILITIES, GW)

CAPACITY TYPE	1976 CAPACITY (GW)	ADDITIONS (1977-1995)		TOTALS TO 1995*	
		MODERATE GROWTH	HIGH GROWTH	MODERATE GROWTH	HIGH GROWTH
Nuclear	41.4	338	347	378	387
Coal	189.9	204	390	403	589
Oil	81.7	37.3	32.3	125	125
Gas	68.4				
Combined Cycle	1.2	6.8	9.5	8.0	10.7
Hydro	65.6	18.8	19.1	86.2	86.5
Turbines	31.4	38.1	66	80	108
Geothermal	0.3	1.6	1.6	1.9	1.9
Other	8.6				
TOTAL (GW)	487.0	575.0	801.0	1082	1308

*Capacity mix for 1995 varies slightly with the control limit assumed: valves here assume 90% SO_2 Removal on coal units on line after 1982.

Source: Teknekron, Inc., 1978. Briefing Memo.

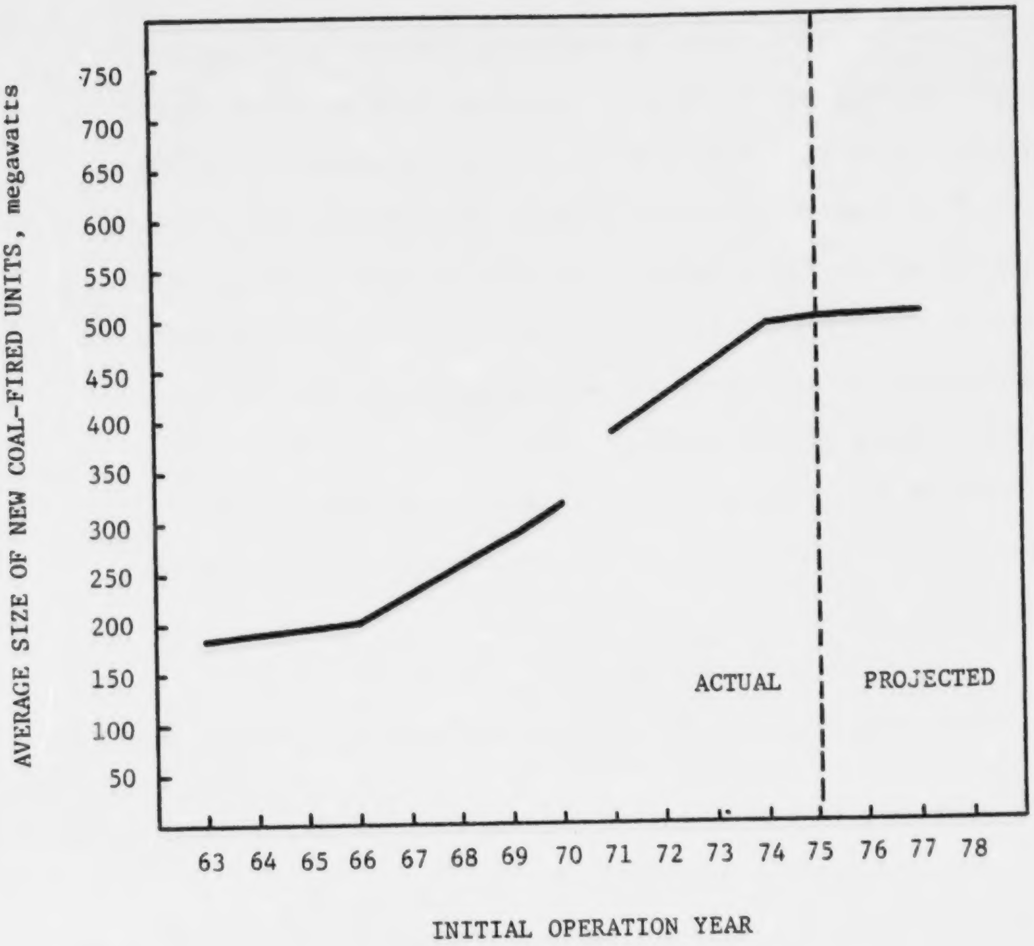


NOTES: (1) Includes units under construction but not yet in commercial operation.
(2) In this and subsequent figures, 5-year running averages are used to smooth out variations caused by relatively small annual sample sizes.

Source: Foster Wheeler Corp., 1976.

FIGURE 7-4

AGGREGATE ANNUAL NUMBER OF INSTALLED COAL-FIRED UNITS OVER 25 MWe ON A 5-YEAR RUNNING AVERAGE



NOTE: Includes units under construction but not yet in commercial application.

Source: Kidder Peabody Co., 1977.

FIGURE 7-5

AVERAGE SIZE OF NEWLY INSTALLED COAL-FIRED UNITS ON A 5-YEAR RUNNING AVERAGE

7.2 Cost Analysis of Alternative Emission Control Systems

7.2.1 New Facilities

At issue are NSPS, which by definition apply to SO_2 emissions from new, modified and reconstructed coal, oil and gas fired steam generators firing more than 73 MW heat input. Facilities established or those that begin construction prior to imposition of the standard are not subject to NSPS. Hence, discussion of control systems and the cost analysis will be limited to new electric generating plants and those modified as defined in the proposed standard.

7.2.2 Basis of Cost Analysis

7.2.2.1 Key Variables. For each SO_2 system discussed in Chapter 4, cost variation is governed principally by the following variables:

- Size of the generating plant
- Coal used (i.e., sulfur content and precombustion costs from source)
- Averaging time over which the plant must meet SO_2 limitations
- Level of control maintained.

In particular, the following control levels were analyzed as scenarios:

- Reduction to 90 percent of what the uncontrolled emissions would be
- Similar reduction to 80 percent
- Maximum emission of 220 ng/J of heat input (0.5 lb/10^6 Btu) of SO_2.

These were compared with the base case: cost of providing the control level specified by current standard of 520 ng/J heat input (1.2 lb SO_2 per 10^6 Btu heat input).

The effects of these variables and of particular ranges of values chosen for them are discussed in the analysis reported in Section 7.2.3. Cost is also influenced by the method chosen for disposal of sludge from the scrubber. This consideration is also discussed in Section 7.2.3.

Another consideration is the redundancy required in FGD equipment. FGD systems installed must be reliable. Because system availability is increased through provision of a spare module, backup equipment is included as a necessary item of the cost estimate. The study incorporated one spare module of the FGD system which included absorbers, pumps, tanks and associated equipment, for units larger than 25 MWe.

7.2.2.2 Modeling Methodology. The method of determining costs was to define typical plants and to model the expenses of operation when values were applied to the variables listed above. This analysis was carried out by PEDCo Environmental, Inc., under contract to the U.S. Environmental Protection Agency. Flue gas desulfurization systems, physical coal cleaning, and use of lower sulfur coal were considered singly and as combined techiques. Cost differentials

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*Other control alternatives were analyzed in connection with particulate controls.

of boilers designed for western subbituminous coals versus eastern coals and transportation costs for coal were taken into account in the analysis (PEDCo, 1977a; 1977b).

A typical new coal-fired plant was defined as a basis for calculations, assuming a midwestern location.* PEDCo then calculated costs for each control alternative, using computer programs developed for the purpose. Mid-1976 costs were used as a basis with an annual escalation rate of 7.5 percent through project completion. The cost estimates obtained were expressed in August 1980 dollars. Five plant capacities were selected for cost modeling: 25, 100, 200, 500 and 1,000 MWe. Other parameters and assumptions of the model plants are detailed in the PEDCo reports (PEDCo, 1977a; 1977b).

Both eastern and western coals and lignite were among the representative range of fuels considered in the cost analyses. Sulfur content of the coals ranged from a low of 0.4 for western lignite to about 7 percent for eastern bituminous. This high-sulfur coal was used for analysis of a boundary condition although 7 percent sulfur coal is rarely if ever burned for power generation in the U.S. Results for coals with specific sulfur content are presented in Tables 7-3 and 7-4 discussed in Section 7.2.3. Additional details may be found in the PEDCo reports (1977a, 1977b).

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*East North Central Region (PEDCo, 1977a, Table 4-1, Page 4-8). Different types of coal were (as noted below) considered in calculating costs.

The costs of SO_2 control by an FGD system are affected by the averaging time over which the emission regulation must be met. As the averaging period decreases, the FGD systems must be designed to cope with a higher average sulfur content of coal. This feature results from the variability of sulfur content in the coal; over a short period of time there is a greater likelihood of high average sulfur content for that period than over a longer period during which variability in the coal used tends to level out. Results within a specific averaging period are affected also by variations in system load and by features of the pollution control system itself, particularly its efficiency, flexibility and reliability. For determining most FGD system costs, an averaging time of 3 hours was assumed. To assess the impacts of different averaging times in the cost of FGD controls, a lime FGD system was modeled using four different averaging periods, as well as a variety of plant sizes and coal types. It was found that as the averaging time lengthens, costs decrease more strikingly from the increased variability of sulfur reflected in the lesser amounts used during a short averaging time. Capital cost for a 25 MWe plant was estimated to decrease by about 3.7 percent from the figures shown in Table 7-4 (from about \$290 per kW to about \$279 per kW) with coal having a nominal content of 3.5 per-cent sulfur if the averaging time were lengthened from 3 hours to a year. In contrast, the decrease reflected between these two averaging times when the same coal is used in a 1000 MW plant was estimated to be 2.8 percent (representing the difference between costs of about $116 and $112.66 per kW). Also, the cost penalty for reduced averaging times is decreased as the sulfur content of the coal decreases. For 0.8 percent sulfur coal cost decreases between a 3-hour and a one-year averaging period are 2.8 percent for a 25 MW plant and less than one percent for a plant of 100 MW capacity.

7.2.2.3 Components of Cost. The study considered capital costs, both direct and indirect, and annual operating and maintenance (O&M) costs. Direct costs represent purchase of equipment items and the costs of labor and material necessary to install the facilities and connect the systems (e.g., site development, sludge disposal, piping and electrical work). Indirect costs include engineering costs, freight, interest, taxes, spare parts, land required for sludge disposal, and other necessary outlays that cannot be charged against any particular equipment items. It should be noted that replacement capacity required as a result of the energy penalty associated with SO_2 control is taken into account. The total direct and indirect costs are expressed as capital investment required in dollars per kilowatt ($/kW) of rated capacity. Capital costs are also translated into annual fixed charges classified under the components of depreciation, taxes, insurance and capital charges, i.e., annual interest. The fixed charges can then be expressed as mills per kilowatt hours (mills/kWh) of electrical energy provided as annual output.

TABLE 7-3

COSTS OF SO_2 CONTROL ALTERNATIVES FOR LEVEL OF 1.2 lbs/10^6 BTU

COAL TYPE, % SULFUR BOILER CAPACITY, megawatts	LIME FGD				LIMESTONE FGD				MAG-OX FGD				DOUBLE ALKALI FGD				WELLMAN-LORD FGD			
	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL
Eastern, 3.5																				
25	262.76	10.38	10.50	20.88	278.48	10.78	11.13	21.91	409.12	14.52	16.35	30.87	308.00	11.16	12.31	23.47	370.24	13.19	14.79	27.98
100	234.78	6.83	9.38	16.21	285.77	7.25	11.42	18.67	319.66	8.59	12.77	21.36	297.70	7.84	11.89	19.73	290.22	7.36	11.60	18.96
200	174.46	5.48	6.97	12.45	202.46	5.58	8.09	13.67	210.41	6.17	8.41	14.58	194.78	5.91	7.78	13.69	188.91	5.21	7.55	12.76
500	124.93	4.69	4.99	9.68	142.58	4.45	5.70	10.15	156.76	5.10	6.26	11.36	147.09	5.14	5.88	11.02	141.16	4.20	5.64	9.84
1000	103.71	4.09	4.14	8.23	119.02	4.03	4.76	8.79	131.00	4.43	5.23	9.66	119.60	4.47	4.78	9.25	116.05	3.58	4.64	8.22
Eastern, 7.0																				
25	321.06	12.46	12.83	25.29	338.64	12.88	13.53	26.38												
100	290.51	8.76	11.61	20.43	352.58	9.01	14.09	23.10												
200	217.36	7.21	8.68	15.89	252.11	7.10	10.07	17.17												
500	156.34	6.06	6.25	12.31	185.94	5.86	7.43	13.29												
1000	131.59	5.56	5.26	10.82	156.53	5.32	6.25	11.57												
Anthracite																				
500																				
Lignite																				
500	96.67	3.06	3.86	6.90																

[a] Mills per kilowatt-hour.

Source: PEDCo, 1977a.

TABLE 7-4

COSTS OF SO_2 CONTROL ALTERNATIVES FOR 90% SO_2 REMOVAL

COAL TYPE, % SULFUR BOILER CAPACITY, megawatts	LIME FGD				LIMESTONE FGD				MAG-OX FGD				DOUBLE ALKALI FGD				WELLMAN-LORD FGD			
	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	mills/kWh	TOTAL
Eastern, 3.5																				
25	289.96	11.01	11.59	22.60	307.60	11.43	12.29	23.72	439.40	15.15	17.56	32.71	337.60	11.86	13.49	25.35	395.76	13.65	15.81	29.46
100	259.88	7.44	10.38	17.82	316.67	7.88	12.65	20.53	354.17	9.26	14.15	23.41	329.64	8.56	13.17	21.73	317.53	7.82	12.69	20.51
200	194.23	5.99	7.76	13.75	225.08	6.09	8.99	15.08	233.21	6.68	9.32	16.00	215.57	6.47	8.61	15.08	206.02	5.54	8.23	13.77
500	139.46	5.15	5.57	10.72	160.15	4.90	6.40	11.30	174.60	5.59	6.98	12.57	163.79	5.67	6.54	12.21	154.93	4.51	6.19	10.70
1000	115.91	4.50	4.63	9.13	134.06	4.44	5.36	9.80	146.93	4.84	5.87	10.71	133.76	4.92	5.34	10.26	127.56	3.81	5.10	8.91
Eastern, 7.0																				
25	322.48	12.64	12.88	25.52	339.88	13.03	13.58	26.61	481.56	16.56	19.24	35.80	374.92	13.75	19.98	33.73	417.48	14.01	16.68	30.67
100	291.52	8.91	11.65	20.56	353.70	9.16	14.13	23.29	398.03	10.37	15.90	26.27	364.41	10.25	14.56	24.81	336.49	8.04	13.44	21.48
200	218.09	7.35	8.71	16.06	252.70	7.23	10.10	17.33	264.99	7.81	10.59	18.40	242.43	8.04	9.69	17.73	220.93	5.22	8.83	14.05
500	157.17	6.30	6.28	12.58	186.59	6.00	7.46	13.46	205.81	6.77	8.22	14.99	183.80	7.32	7.34	14.66	169.24	4.81	6.76	11.57
1000	132.02	5.69	5.27	10.96	157.05	5.45	6.27	11.72	173.01	5.85	6.91	12.76	151.11	6.30	6.04	12.34	140.36	4.00	5.61	9.61
Western, 0.8																				
25	252.52	9.68	10.09	19.77	269.16	10.10	10.75	20.85												
200	166.09	4.91	6.64	11.55	192.13	5.18	7.68	12.86												
500	119.42	3.95	4.77	8.72	137.20	4.11	5.48	9.59												
Anthracite																				
500	116.57	3.67	4.66	8.33																
Lignite																				
500	116.71	3.71	4.66	8.37																

[a] Mills per kilowatt-hour.

Source: PEDCo, 1977a.

TABLE 7-5

COSTS OF SO_2 CONTROL ALTERNATIVES FOR LEVEL OF 220 ng/J (0.5 lb/10^6 BTU)

COAL TYPE, % SULFUR BOILER CAPACITY megawatts	LIME FGD				LIMESTONE FGD				COMBINATION								COMBINATION							
									COAL CLEANING				LIME FGD				COAL CLEANING				LIMESTONE FGD			
	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $ kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL	CAPITAL $/kW	O&M[a] mills/kWh	FIXED mills/kWh	TOTAL
Western, 0.8																								
25	226.68	9.05	9.06	18.11	241.76	9.43	9.66	19.09																
200	146.68	4.38	5.86	10.24	169.93	4.63	6.79	11.42																
500	105.44	3.51	4.21	7.72	119.95	3.64	4.79	8.43																
Eastern, 7.0																								
500									16.45	20.17	2.21	22.38	136.77	3.93	5.46	9.39	16.45	7.49	2.31	9.70	157.51	3.93	6.29	10.22

[a] Mills per kilowatt hour.

Source: PEDCo, 1977a.

Annual O&M costs of an SO_2 control system represent the costs of utilities required, including fuel; operating labor; maintenance and repairs; and energy penalty costs (Section 7.3.2) resulting from the fact that the control equipment uses energy and results in a requirement to generate additional power output. Also included are overhead expenses for safety, employee benefits, engineering and legal services that cannot be attributed to any specific part of the control process.

7.2.3 Estimated Control Costs

Estimates of the costs of the various control alternatives to utility electric generating plants are summarized in Tables 7-3, 7-4, and 7-5. These tables show the capital costs in terms of dollars per kilowatt, which are then amortized as fixed costs expressed in mills per kilowatt-hour at approximately 4 percent. Fixed costs are added to the O&M to get the total costs in mills per kilowatt-hours. Table 7-3 provides costs for meeting current SO_2 control standards of 520 ng/J (1.2 $lb/10^6$ Btu) as a base case, which may be compared with the costs of providing 90 percent reduction (Table 7-4) and meeting an absolute level of 220 ng/J (0.5 $lb/10^6$ Btu) (Table 7-5).* It is seen from the tables that economies of scale result in considerably lower (but non-linearly decreasing) costs for larger plant sizes. The incremental costs of providing 90 percent SO_2 reduction over those of the baseline case are listed for lime and limestone in Table 7-6.

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*Costs for 80 percent SO_2 reduction were not supplied by PEDCo.

TABLE 7-6

INCREMENTAL COSTS OF REMOVING 90% SO_2 (COMPARED TO COSTS OF MEETING 1.2 $lb/10^6 Btu$)

CONTROL ALTERNATIVE	LIME FGD				LIMESTONE FGD			
Coal Type,* % Sulfur, Boiler Capacity, Megawatts	Capital $/kw	O & M m/kwh	Fixed m/kwh	Total mills/kwh	Capital $/kw	O & M m/kwh	Fixed m/kwh	Total mills/kwh
Eastern, 3.5								
25	27.20	0.63	1.09	1.72	29.12	0.65	1.16	1.81
100	25.10	0.61	1.00	1.61		0.63	1.23	1.86
200	19.77	0.51	0.79	1.30	22.62	0.51	0.90	1.41
500	14.53	0.46	0.58	1.04	17.57	0.45	0.70	1.15
1000	12.20	0.41	0.49	0.90	15.04	0.41	0.60	1.01
Eastern, 7.0								
25	1.40	0.18	0.05	0.23	1.24	0.15	0.05	0.20
100	1.01	0.15	0.04	0.19	1.12	0.15	0.04	0.19
200	0.73	0.14	0.03	0.17	0.59	0.13	0.03	0.16
500	0.83	0.24	0.03	0.27	0.65	0.14	0.03	0.17
1000	0.43	0.13	0.01	0.14	0.52	0.12	0.02	0.14
Lignite								
500	20.04	0.65	0.80	1.45				

*Western 0.8 percent sulfur coal and eastern anthracite coal are not shown. These are assumed to require no FGD to meet current standards. Therefore, the total costs for removing 90 percent SO_2 are "incremental" over the baseline situation.

Source: PEDCo., 1977a.

Combined precombustion cleaning of coal with use of FGD was also considered and is discussed later.

A striking, although not unexpected feature of the PEDCo analysis, is that the incremental costs vary inversely with the sulfur content of the coal. That is, it is much less expensive incrementally to go from a 520 ng/J (1.2 lb/10^6 Btu) standard to a 90 percent reduction of SO_2 from high sulfur coal (e.g., 7.0 percent) than from coal containing smaller amounts of sulfur (e.g., 3.5 percent). These results are summarized in Table 7-6 for the lime and limestone FGD alternatives.

Here it is seen that the incremental capital costs (over the baseline situation of maintaining current NSPS) of providing 90 percent SO_2 reduction for eastern coal containing 3.5 percent sulfur range from \$8.30 to \$21.63 per kilowatt of capacity for using lime FGD or on the order of 1/10 the total costs (as given in Table 7-4) for this scenario. On a mill per kilowatt-hour basis, the incremental costs of this method add roughly 1/10 of a cent to the cost of each kilowatt-hour of output. For high sulfur (7 percent) eastern coal the incremental costs are almost negligible--less than \$1/kW capitalization and a fraction of a mill per kWh in the extreme situation.

For low-sulfur western coal (assumed in the study to require no controls in order to meet current standards) the total costs of removing 90 percent of SO_2 would represent incremental expenses that add from about 1 to 2 cents to the cost per kilowatt-hour (depending on generating plant size). The projected total costs of meeting the 220 ng/J (0.5 $lb/10^6$ Btu) SO_2 limit (as shown in Table 7-5) for western coal represent incremental control costs over those required by current standards. It should be noted that for low-sulfur western coal it is less costly to meet the 220 ng/J (0.5 $lb/10^6$ Btu) level than to reduce the SO_2 emissions by 90 percent because the 220 ng/J level requires less than 90 percent reduction of SO_2.

It is also noteworthy that the combination of precombustion cleaning of coal to remove pyritic sulfur followed by FGD was not found to be cost-effective when other alternatives are applicable. The study indicates that the combined methodology would be appropriate only with coals so high in sulfur that FGD alone would not meet NSPS. This situation is represented for 7 percent sulfur-content eastern coal (an extreme case) in relation to the 220 ng/J (0.5 $lb/10^6$ Btu) standard in Table 7-5.

Costs of SO_2 control are also influenced by the method used to dispose of scrubber sludge. Ponding and landfilling are the two basic methods. The costs developed by PEDCo are based on an assumption of sludge disposal in an on-site pond lined with clay. The sludge would be stabilized by addition of fly ash and lime. This method is calculated to add 1.15 mills/kWh to the cost of electricity generation. Alternatives such as the use of synthetic lining, chemical fixation and pumping are estimated to add additional costs from 0.15 mills/kWh for proprietary fixation to more than 3 mills/kWh for trucking over extended distances.

7.3 Other Cost Considerations

7.3.1 Additional Capital and Operating Costs

In addition to control of SO_2 emissions, a number of environmental regulations apply to coal-fired generating plants. This section considers the principal capital and operating costs associated with these plants. The analysis is based on a model 600-MWe coal-fired unit, corresponding to the size chosen for the representative plants analyzed in determining costs of SO_2 control (see Section 7.4.1). Estimated capital and operating costs for the major items of control considered for such a plant are shown in Table 7-7.

TABLE 7-7

ENVIRONMENTAL CAPITAL COSTS FOR REPRESENTATIVE NEW PLANT[a]
(1975 dollars)

Control Device	Unit Cost/kW	Total Industry Cost, millions of dollars	Annual O&M Costs, mills/kWh
Chemical Effluent Treatment	1.52	0.9	0.3
Mechanical Cooling Tower	5.77	3.46	0.2
Entrainment Screens	4.08	2.45	0.1
Total	11.37	6.81	0.6

[a] Based on a new 600-MW coal-fired unit.

Source: Temple, 1976.

TABLE 7-8

CAPITAL EXPENDITURES 1975-1985 BY TYPE OF POLLUTION CONTROL EQUIPMENT

(Excluding equipment built for reasons other than compliance with Federal regulations)

Water Regulations	Capital Expenditures billions of 1975 dollars
Chemical Treatment	1.2
Cooling Towers	2.6
Entrainment Screens and Cooling Towers	0.6
Total Costs	4.4

Source: Temple, 1976.

TABLE 7-9

O&M EXPENSES FOR THE INDUSTRY

Impacts	1975-1985 billions of 1975 dollars
Water Regulations	6.1
Air Regulations	19.0
Total Costs	25.1

Source: Temple, 1976.

Table 7-8 shows the total capitalization requirements attributable to control costs of water regulations in the electric utility industry for the period 1975-85. The cumulative operating and maintenance expenses associated with this equipment between 1975 and 1985 total $6.1 billion as shown in Table 7-9.

7.3.2 Energy Penalty Costs Associated with SO_2 Control

Table 7-10 presents the energy penalty costs in mills per kilowatt-hour resulting from the imposition of selected control systems for particular plant sizes and coal types under specified scenarios. It should be noted that these costs have been included in the cost tables of Section 7.2 as part of the total costs expressed in mills per kilowatt-hour. Therefore, they are not additive to other costs shown but are presented here for consideration as part of the control costs.

7.4 Economic Impact of Alternative Control Systems

7.4.1 Increased Costs to Utility Industry

7.4.1.1 Method of Calculation. The economic and financial impacts of the NSPS on the electric utility industry reported here are based on results developed by Teknekron, Inc. (1978). Impacts were calculated for the nation as a whole and regionally for individual measures under specific scenarios that differ as to assumed growth rates for production of electric energy and imposed control standards.

TABLE 7-10

ENERGY PENALTY IN MILLS/KWH[b] FOR SELECTED CONTROL PROCESSES, SCENARIOS AND PLANT SIZES

Coal Type	% Sulfur	Plant Capacity in MW	FGD Process and Scenario								
			Lime or Limestone*			Magnesium Oxide		Double Alkali		Wellman-Lord	
			1.2 LB SO_2/ 10^6 Btu	90% SO_2 Reduction	0.5 LB SO_2/ 10^6 Btu	1.2 LB SO_2/ 10^6 Btu	90% SO_2 Reduction	1.2 LB SO_2/ 10^6 Btu	90% SO_2 Reduction	1.2 LB SO_2/ 10^6 Btu	90% SO_2 Reduction
Eastern	3.5 to 7.0	25	0.88	0.97	a	1.05	1.16	0.88	0.97	1.05	1.16
		200	0.80	0.88	a	0.95	1.05	0.80	0.88	0.95	1.05
		500	0.77	0.85	a	0.92	1.02	0.77	0.85	0.92	1.02
		1000	0.75	0.83	a	0.90	0.99	0.75	0.83	0.90	0.99
Eastern (With Coal Cleaning)	3.5	500	12.68	a	a	a	a	a	a	a	a
Anthracite	0.8	500	0.77	0.85	a	a	1.02	a	0.85	a	1.02
Western	0.8	25	a	1.16	0.97	a	1.39	a	1.16	a	1.39
		200		1.06	0.88		1.26		1.06		1.26
		500		1.02	0.85		1.22		1.02		1.22
Western Lignite	0.4	500	0.77	0.85	a	a	1.02	a	0.85	a	1.02

*Costs calculations as reported were virtually identical for both processes.

a - Not reported.

b - Costs represent the purchase price of power from the unit to run the FGD system.

Source: PEDCo. Environmental Special Communication, January 31, 1978.

TABLE 7-11

ALTERNATIVE TEKNEKRON NSPS SCENARIOS

Teknekron Scenario Label	Revised NSPS Maximum Emission Level in lb/10^6 Btu (% Removal)
Moderate Growth Scenarios[a]:	
M1.2(0)0.1 (Baseline)	SO_2 = 1.2 (0) NO_x = 0.7 Particulates = 0.1
M1.2(90)0.1	SO_2 = 1.2 (90) NO_x = 0.6 Particulates = 0.1
M1.2(90)0.03	Same as M1.2(90)0.1 but with Particulates = 0.03
M1.2(80)0.03	SO_2 = 1.2 (80) NO_x = 0.6 Particulates = 0.03
M0.5(0)0.03	SO_2 = 0.5 (0) NO_x = 0.6 Particulates = 0.03
High Growth Scenarios[b]:	
H1.2(0)0.1 (Baseline)	SO_2 = 1.2 (0) NO_x = 0.7 Particulates = 0.1
H1.2(90)0.1	SO_2 = 1.2 (90) NO_x = 0.6 Particulates = 0.1
H1.2 (90)0.03	Same as H1.2(90)0.1 but with Particulates = 0.03
H1.2(80)0.03	SO_2 = 1.2 (80) NO_x = 0.6 Particulates = 0.03

[a] 5.8% per year to 1985; 3.4% thereafter.
[b] 5.8% per year to 1985; 5.5% thereafter.
Source: Teknekron, Inc., 1978.

The present standard of a maximum emission rate of 520 ng/J (1.2 lb $SO_2/10^6$ Btu) heat input is used as a baseline case in order to assess the effects of the following assumed standards:

- A reduction of 90 percent of SO_2 emissions over what the uncontrolled level would be with a ceiling of 520 ng/J heat input
- A corresponding reduction of 80 percent with a ceiling of 520 ng/J heat input
- A maximum of 220 ng/J (0.5 lb $SO_2/10^6$ Btu) regardless of the degree of reduction.

Scenarios for which calculations were performed by Teknekron are listed in Table 7-11.*

Regional results are allocated among 10 regions, nine of which correspond to those used by the U.S. Bureau of the Census. However, the Mountain Region is divided into northern and southern portions which are separately allocated. A listing of the states in each region is provided in Table J-4 of Appendix J.

In performing the calculations, Teknekron used a computerized utility simulation model developed for EPA's Integrated Technology Assessment program (Teknekron, Inc., 1977a). The financial module of the model is an accounting structure that treats financial transactions (in this case, those associated with construction and operation of electric generating plants) in a prespecified way. It simulates the treatment of these transactions by regulatory and tax authorities and readjusts revenue requirements for the coming year. Pollution control cost data were adjusted to be consistent with those developed by PEDCo, as discussed in the preceding section.

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*To provide a more consistent basis for comparison with the baseline situation, results in this report generally reflect for the 90 percent SO_2 reduction scenario the Teknekron calculations assuming 0.1 lb of particulates/10^6 Btu. Although this particulate level was not calculated by Teknekron for other scenarios, differences between the 0.1 and 0.03 lb level for particulates in the 90 percent SO_2 reduction scenario were so slight as to indicate that no significant discrepancies were introduced by using the 0.03 lb particulates/10^6 Btu level elsewhere.

The computer simulations were based on meeting the requirements for power as projected by each scenario (Table 7-2). For existing generating units and new units that have already been scheduled, the simulations used data provided by the utility companies concerned which included size and authorized or projected site locations. For the years after 1985, for which data on plant schedules are largely nonexistent, the simulation determined the need for plants in particular locations to meet power growth requirements. In simulations involving the post-1985 period, an average coal-fired unit of 600-MWe rated capacity was assumed for new units and site locations were selected, with counties containing Class I or nonattainment areas excluded.

Included in the output from the Teknekron simulation runs were:

- Component costs of supplying electricity and the effects that the various proposed NSPS will have on capitalization and costs for pollution control, for fuel, and for other operation and maintenance. (Section 7.4.1.2.)
- Effects that alternative revisions of the NSPS can be expected to have on key parameters indicating the financial status of the electric utility industry. These results are discussed in Section 7.4.2.

- National and regional effects in terms of relative increases in the price of electricity (Section 7.4.3).

7.4.1.2 Effect on Costs of Generating Electricity. The nationwide costs to the utility industry of generating electricity for the baseline situation (assuming that the current maximum of 520 ng/J of SO_2 is continued) and for the alternative revisions considered for NSPS are shown in Tables 7-12 and 7-13. These tables show for each scenario the total costs (on a national basis) that the industry must meet in the period of 1980-1995. Also shown is the incremental cost of each alternative in a monetary unit and as a percentage increase. Incremental monetary cost is determined as the difference between costs under the assumed NSPS and costs in the baseline situation. The percentage increase is determined as the ratio of this difference to the baseline cost. Further information includes the allocation of costs to pollution control, fuel and other expenditures. Table 7-12 gives the results for moderate power growth and Table 7-13, a high growth rate.

Costs to the industry of alternative NSPS are measured in part by the proportion of yearly expenditures that must be allocated to pollution control as compared with other major outlays such as fuel and O&M. The distribution of costs are shown nationwide in Tables 7-12 and 7-13. Both investment requirements and operating costs (i.e., operation and maintenance of pollution control equipment) attributable to pollution control are compared with other expenditures.

TABLE 7-12

NATIONWIDE COSTS OF GENERATING ELECTRICITY
UNDER ALTERNATIVE NSPS 1986 - 1995
MODERATE RATE OF POWER GROWTH

Allocation	Baseline[a]	90% SO_2 Removal		80% SO_2 Removal		0.5 lb $SO_2/10^6$ Btu	
	Dollars[b]	Dollar Cost[b]	Increment Over Baseline	Dollar Cost[b]	Increment Over Baseline	Dollar Cost[b]	Increment Over Baseline
Total Revenue	1,149.5	1,171.6	22.1	1,170.4	20.9	1,170.0	20.5
Total Cost	1,023.9	1,050.6	26.7	1,049.7	25.8	1,049.4	25.5
Fuel	369.8	369.5	-0.3	369.5	-0.3	368.9	-0.9
Pollution Control	36.4	43.6	7.2	43.3	6.9	43.4	7.0
Other Operation and Maintenance[c]	167.4	167.9	0.5	165.9	0.5	167.9	0.5
Pollution Control Investment	8.0	21.0	13.0	21.3	13.3	21.3	13.3
All other Investments[c]	325.3	329.5	4.2	328.4	3.1	328.7	3.4
Net Profit	125.6	121.0	-4.6	120.7	-4.9	120.6	-5.0

[a] Continuation of present standard -520 ng/J (1.2 lb $SO_2/10^6$ Btu).

[b] Billions of 1975 dollars.

[c] Excluding pollution control.

[d] Ratio of increment to baseline cost (where this is a positive value).

Source: Teknekron, Inc., 1978.

TABLE 7-13

NATIONWIDE COSTS OF GENERATING ELECTRICITY
UNDER SELECTED ALTERNATIVE OF NSPS 1986-1995
HIGH RATE OF POWER GROWTH

Allocation	Baseline[a]	90% SO_2 Removal[f]		80% SO_2 Removal	
	Dollars[b]	Dollar Cost[b]	Increment Over Baseline (dollars)	Dollar Cost[b]	Increment Over Baseline (dollars)
Total Revenue	1,346.1[e]	1,387.1[e]	41.0[e]	1,393.6[e]	42.5[e]
Total	1,197.1	1,250.0	52.9	1,251.4	54.3
Fuel	432.6	435.2	2.6	435.3	2.7
Pollution Control	40.0	54.9	14.9	51.1	11.1
Other Operation and Maintenance[c]	196.1	197.0	1.0	196.9	0.8
Pollution Control Investment	17.6	48.3[f]	30.7	47.7	30.1
Net Profit	140.0	137.1	-2.9	137.2	-2.8
All Other Investments[c]	518.8	524.2	5.4	523.1	4.3

[a] Continuation of present standard-520 ng/J (1.2 lb $SO_2/10^6$ Btu).

[b] Billions of 1975 dollars.

[c] Excluding pollution control.

[d] Ratio of increment to baseline value.

[e] Detailed items do not sum to totals because miscellaneous costs were not included.

[f] Assuming a particulate level of 0.1 lb/10^6 Btu.

Source: Teknekron, Inc., 1978.

It should be stressed that allocation of costs to pollution control provides a somewhat different representation of the financial impacts of NSPS from that given by an incremental increase in total costs. Differences in the kinds and amounts of fuel and in O&M requirements occasioned by NSPS are not attributed directly to the cost of the revised control standards; instead, these differences appear as part of the fuel and O&M costs.

It can be seen from Table 7-12 that there is little variation in the effects of the alternatives. Under moderate growth all are projected to increase total costs by about $26 billion, a percentage increase of 2.52 to 2.61. As would be expected, a major component of the increase is for pollution control. Under the assumption of a high growth rate of power, total costs increase by about 4.5 percent.

Tables 7-14 and 7-15 expand the operational pollution control costs to regional figures.* Baseline (i.e., assuming maintenance of present standards) costs are compared to those under alternative NSPS revisions and incremental expenditures of the revisions are shown. For the moderate growth of power, alternative revisions considered are 90 percent SO_2 reduction, 80 percent SO_2 reduction, and a ceiling of 220 ng/J (0.5 lb $SO_2/10^6$ Btu). Only the first two of these scenarios have cost estimates shown for the high growth assumption. Here marked disparities appear among the various regions in the scenarios. The burden (on a percentage increase basis) will fall heavily on the utilities in the West South Central and Northern Mountain regions and, secondarily, on those in the South Atlantic and Pacific regions and (under high growth) also in the Mid-Atlantic and North Central regions. In both the moderate and the high growth scenarios, maximum costs occur under the assumption of 90 percent renewal of SO_2. In several regions, costs for the ceiling of 220 ng/J (0.5 lb $SO_2/10^6$ Btu) (moderate growth assumption) are estimated to equal those of 90 percent SO_2 reduction.

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*Regional costs to consumers in the price of electricity expressed as mills/kWh are discussed in subsection 7.4.3.

Under moderate growth, costs will increase in the West South Central region by as much as 80.5 percent, up to $3.3 billion; and under high growth as much as 84.8 percent, up to $3.8 billion. In the Northern Mountain region under high growth maximum incremental pollution control costs would be $0.4 billion, an increase of 133.33 percent. Under high growth, the Pacific region could face cost increases up to 58.3 percent ($1.4 billion) and under moderate growth increases of more than 26 percent ($0.5 billion). South Atlantic region increases run up to 38.8 percent ($2.1 billion) under moderate growth and up to 38.8 percent ($3.1 billion) under high growth. East North Central increases under high growth could amount to $2.6 billion, an increase of 25.2 percent. Under high growth, the Mid-Atlantic region is projected to increase as much as 69.8 percent ($3 billion). By contrast, New England and the East South Central regions will be relatively unaffected (increases from virtually

TABLE 7-14

POLLUTION CONTROL COSTS BY REGION FOR ALTERNATIVE NSPS REVISIONS, 1986-1995 [a]

Region	Moderate Growth of Power							
	Baseline [a]		90% SO_2 Reduction		80% SO_2 Reduction		0.5 lb $SO_2/10^6$ Btu	
	Cost 1976-85	Cost 1986-95	Cost 1986-95	Percent [c] Increase	Cost 1986-95	Percent [c] Increase	Cost 1986-95	Percent [c] Increase
Nation	\$20.2 [d]	\$36.4 [d]	\$44.3 [d]	21.4	\$43.3 [d]	19.0	43.2 [d]	19.5
New England	0.3	0.9	0.9	(e)	0.9	(e)	0.9	(e)
Mid- Atlantic	2.7	5.0	5.5	10.0	5.3	6.0	5.5	10
S. Atlantic	4.0	7.0	9.1	30.0	8.9	27.1	9.0	28.6
E. N. Central	5.3	8.5	8.8	3.5	8.8	3.5	8.8	3.5
E. S. Central	2.3	4.0	4.2	5.0	4.1	2.5	4.1	2.5
W. N. Central	1.3	2.2	2.6	18.2	2.6	18.2	2.5	13.6
W. S. Central	1.9	4.1	7.4	80.5	7.1	73.2	7.0	70.7
N. Mountain	0.1	0.3	0.4	33.3	0.4	33.3	0.4	33.3
S. Mountain	1.5	2.5	3.0	20.0	2.8	12.0	2.7	8.0
Pacific	0.8	1.9	2.4	26.3	2.4	26.3	2.4	26.3

[a] Costs include expenses for SO_2, NO_x, TSP and related pollution abatement equipment O&M.

[b] Continuation of present standard-520ng/J (1.2 lb $SO_2/10^6$ Btu).

[c] Percent change from baseline scenario.

[d] Billions of 1975 dollars.

[e] Less than 1/10 of 1 percent.

Source: Teknekron, Inc., 1978.

TABLE 7-15

POLLUTION CONTROL COSTS BY REGION FOR
ALTERNATIVE NSPS REVISIONS, 1986-1995[a]

Region	High Growth of Power					
	Baseline[b]		90% SO_2 Removal		80% SO_2 Removal	
	1976-85	1986-95	1986-95	Percent Increase	1986-95	Percent Increase
Nation	\$19.1[c]	\$40.0[c]	\$56.3[c]	38.8[d]	\$53.4[c]	33.5
New England	0.3	1.1	1.2	9.1	1.1	—[a]
Mid-Atlantic	2.3	4.3	7.3	69.8	6.9	60.5
S. Atlantic	4.0	8.0	11.1	38.8	10.6	32.5
E. N. Central	4.9	10.3	12.9	25.2	12.5	21.4
E. S. Central	2.1	3.8	4.3	13.2	4.0	5.3
W. N. Central	1.2	2.5	3.3	32.0	3.3	32.0
W. S. Central	1.9	4.6	8.5	84.8	7.9	71.7
N. Mountain	0.1	0.3	0.7	133.33	0.5	66.7
S. Mountain	1.5	2.7	3.2	18.5	3.1	14.8
Pacific	0.8	2.4	3.8	58.3	3.6	50.0

[a] Costs include expenses for SO_2, NO_x, TSP and related pollution abatement equipment operation and maintenance.

[b] Continuation of present standard-520ng/J (1.2 lb $SO_2/10^6$ Btu).

[c] Billions of 1975 dollars.

[d] Percent change from baseline scenario.

[e] Less than 1/10 of 1 percent.

Source: Teknekron, Inc., 1978

nothing up to about 13 percent and $0.5 billion). Under moderate growth, the East Central regions will receive among the lightest impacts (percentage increases from between 2.5 and 5.0 percent and dollar increases not exceeding $0.3 billion).

7.4.2 Financial Impact on Utility Industry

The impacts of the alternative control levels under NSPS on the electric utility industry are measured by several key parameters indicative of the industry's financial status. These parameters were calculated by the Teknekron model. Table 7-16 shows the capital investment requirements for the Electric Utility Industry (EUI) on a nationwide basis under assumptions of both moderate and high growth. The total capital investment required for the baseline scenarios (maintenance of present standards) is given in billions of 1975 dollars. The required increments are shown for pollution control and other expenses under the selected NSPS revision. As shown, the overall percentage of changes attributable to revised NSPS is small--about 3 percent for moderate growth and slightly over 5 percent for high growth. However, the increase in capital investment for pollution control is more than 43 percent (about $14.6 billion) for moderate growth and nearly double the percentage to 82.3 ($34.4 billion additional) for the high growth scenario.

Incremental impacts of alternative NSPS revisions on total U.S. capital investment, Gross National Product (GNP) and new debt and equity issues do not appear significant. Even under the high growth

TABLE 7-16

CAPITAL INVESTMENT

By Electric Utility Industry (Investor-Owned and Municipal)
Under Alternative NSPS Revisions, 1976-95

(Billions of 1975 dollars)

Growth Rate	Baseline Capital Investment excluding Pollution Control	Baseline Capital Investment in Pollution Control	Capital Investment excluding Pollution Control due to Alternative NSPS Revision	Change due to Alternative NSPS Revision	Capital Investment in Pollution Control due to Alternative NSPS Revision	Change due to Alternative NSPS Revision, %	Overall Incremental Capital Investment due to Alternative NSPS Revision	Overall Percent Change due to Alternative NSPS Revision
Moderate								
Baseline[a]	531.9	33.5	-	-	-	-	-	-
80% SO_2 Reduction	-	-	2.8	0.5	13.3	43.6	17.4	3.1
90% SO_2 Reduction	-	-	3.9	0.7	14.6	43.4	18.4	3.2
High								
Baseline[a]	724.8	41.9	-	-	-	-	-	-
90% SO_2 Reduction	-	-	6.9	1.0	34.4	82.3	41.4	5.4

[a] Continuation of present standard - 520 ng/J (1.2 lb $SO_2/10^6$ Btu).

Source: Teknekron, Inc., 1978.

scenarios, the ratio of Incremental Capital Investment due to NSPS to GNP amounted to 1 percent by the year 1990. These findings were based on the TRENDLONG 0877 forecast of GNP provided by Data Resources, Inc.* (Teknekron, Inc., 1978).

Table 7-17 shows the expected long-term external financing by the industry in providing for the capitalization requirements. Relative financial impacts are shown nationally and for each of the 10 regions under the scenarios in terms of three selected parameters characterizing the EUI in Tables 7-18, 7-19 and 7-20. The following are indicative of the industry's financial health and the degree of difficulty likely to be encountered in financing the required growth in electric power under NSPS.

- Return on common (ROC) - equity returns or what stockholders may expect in return for their investment in the EUI.
- Interest coverage (IC) - ratios that tend to vary directly with company earnings. If these ratios are low, they adversely affect bond ratings, interest rates and prices of stock shares, creating difficulty for the EUI in raising the capital needed.
- Earnings quality (EQ) - a measure of the extent to which earnings represent cash and indicative of the extent to which the EUI can expect to attract funds through investment in stock.

The measures shown in these tables indicate that for the most part the impacts in the EUI will be small. Whereas the estimated mean value of ROC (Table 7-18) is for all alternative NSPS depressed

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* The year 1990 is the latest provided by the Data Resources Inc, forecast.

TABLE 7-17

LONG-TERM EXTERNAL FINANCING

By Investor-Owned Electric Utilities
Under Alternative NSPS Revisions, 1976-95

(In billions of 1975 dollars)

	Baseline External Financing			Incremental Long-term External Financing Attributable to Alternative NSPS Revisions			Percent Change Attributable to Alternative NSPS Revisions		
Moderate Growth	Long-Term Debt	Common Stock	Preferred Stock	Long-Term Debt	Common Stock	Preferred Stock	Long-Term Debt	Common Stock	Preferred Stock
Baseline[a]	255.2	87.0	80.8	-----	-----	-----	-----	-----	-----
80% SO_2 Reduction	-----	-----	-----	3.4	6.0	1.0	1.3%	6.9%	1.3%
90% SO_2 Reduction	-----	-----	-----	3.8	6.1	1.2	1.5%	7.0%	1.5%
High Growth									
Baseline[a]	363.7	158.3	113.3	-----	-----	-----	-----	-----	-----
90% SO_2 Reduction	-----	-----	-----	7.7	13.6	2.3	2.1%	8.6%	2.0%

[a] Continuation of present control standards (1.2 lb $SO_2/10^6$ Btu)

Source: Teknekron, Inc., 1978.

from that projected for the baseline situation, under moderate growth assumptions virtually all means fall within the range of values predicted under maintenance of the current NSPS. The only exception is the West South Central region where the mean falls slightly below the lower boundary of the baseline range. In the high growth situation, the effects are more pronounced. The national mean of 10.8 under 90 percent SO_2 reduction is 0.2 below the lower level of the projected range. This drop reflects the same condition projected for three of the 10 regions, and the fact that in the populous Mid and South Atlantic regions the projected mean for the 90 percent scenario is near the baseline lower boundary.

In regard to interest coverage (Table 7-19), all projected means fall within the baseline ranges. It is noteworthy that under all scenarios as well as the baseline situations, the average ratio for New England is projected to fall below 2.0 for at least 1 year of the period 1985-95. Quality of earnings (Table 7-20) are shown as little affected by revised NSPS. It may, therefore, be considered that the effects of revised NSPS on the industry under moderate growth would be small and local. Under high growth, however, return would be depressed nationally.

7.4.3 Effects on Price of Electricity to Consumer

A significant measure of the impacts of NSPS on the average American is the change that can be expected in the price of electric power to the wholesale and retail consumer. This effect has been

TABLE 7-18

RETURN ON EQUITY (RETURN ON COMMON STOCK)

For Investor-Owned Electric Utilities on a Regional Basis
Under Alternative Scenarios, 1985-95

Moderate Growth		Nation	N. Eng.	Mid-Atl.	S.-Atl.	E.N. Central	E.S. Central	W.N. Central	W.S. Central	N. Mtn.	S. Mtn.	Pacifi
Baseline	Mean	12.4%	13.9%	13.1%	10.7%	12.9%	10.9%	14.5%	10.2%	16.5%	13.2%	14.5
	Range	11.8--13.4	11.1--21.3	12.4--14.3	9.1--11.8	11.9--14.0	8.2--13.6	13.2--15.8	9.1--11.0	12.5--18.1	11.0--15.1	13.9--15.2
80% SO_2 Reduction	Mean	12.0	13.9	12.7	10.4	12.8	9.8	13.7	9.0	14.0	12.7	14.3
	Range	11.3--12.7	11.0--21.3	12.1--13.4	8.7--11.4	11.8--13.5	7.6--12.4	12.4--15.8	8.4--9.6	10.8--17.5	11.4--14.3	13.5--14.8
90% SO_2 Reduction	Mean	11.9	13.9	12.6	10.3	12.3	9.7	13.7	8.9	13.9	12.7	14.3
	Range	11.3--12.6	11.0--21.3	12.2--13.3	8.7--11.3	11.8--13.3	7.5--11.7	12.3--14.9	8.3--9.5	10.6--17.4	11.3--14.3	13.5--15.1
High Growth												
Baseline	Mean	11.5	15.4	12.1	10.1	11.6	10.2	13.1	9.5	14.9	12.5	13.2
	Range	11.0--12.9	11.1--22.2	11.1--14.1	9.0--11.7	11.1--12.8	9.2--12.5	12.2--14.2	9.1--10.0	12.1--17.4	11.2--13.9	12.0--14.5
90% SO_2 Reduction	Mean	10.8	15.5	11.4	9.7	10.8	9.5	11.8	7.9	13.5	11.3	12.9
	Range	10.3--11.9	11.0--22.2	10.5--13.0	8.8--10.9	10.3--12.4	8.1--11.7	10.5--13.3	6.8--8.7	9.9--16.9	9.7--13.0	11.9--14.1

Source: Teknekron, Inc., 1978.

TABLE 7-19

INTEREST COVERAGE

For Investor-Owned Electric Utilities on a Regional Basis Under Alternative Scenarios, 1985-95

Moderate Growth		Nation	N. Eng.	Mid-Atl.	S.-Atl.	E.N. Central	E.S. Central	W.N. Central	W.S. Central	N. Mtn.	S. Mtn.	Pacific
Baseline	Mean	3.14	2.52	3.50	2.82	3.44	2.78	3.61	2.63	4.28	3.42	3.70
	Range	2.72 to 3.40	* to 4.43	3.39 to 3.72	2.48 to 3.01	3.32 to 3.61	2.37 to 3.04	3.50 to 3.83	2.41 to 2.76	3.88 to 4.81	3.03 to 3.59	3.54 to 3.84
80% SO_2 Reduction	Mean	3.14	2.52	3.47	2.81	3.43	2.73	3.62	2.62	4.36	3.38	3.68
	Range	2.72 to 3.34	* to 4.43	3.34 to 3.60	2.48 to 3.02	3.26 to 3.56	2.53 to 3.01	3.36 to 3.93	2.38 to 2.75	3.49 to 5.68	3.22 to 3.59	3.45 to 3.83
90% SO_2 Reduction	Mean	3.14	2.54	3.47	2.76	3.42	2.73	3.62	2.62	4.36	3.31	3.68
	Range	2.72 to 3.34	* to 4.43	3.33 to 3.59	2.49 to 3.01	3.25 to 3.57	2.52 to 2.94	3.34 to 3.83	2.37 to 2.72	3.48 to 5.72	3.21 to 3.95	3.45 to 3.83
High Growth												
Baseline	Mean	3.01	3.23	3.24	2.67	3.27	2.66	3.30	2.55	3.71	3.14	3.37
	Range	2.59 to 3.22	* to 4.43	3.10 to 3.53	2.45 to 2.83	3.16 to 3.40	2.50 to 2.97	3.18 to 3.48	2.41 to 2.68	3.32 to 4.18	2.99 to 3.33	3.18 to 3.60
90% SO_2 Reduction	Mean	2.97	3.22	3.21	2.68+	3.19	2.66	3.25	2.49	3.68	3.10	3.31
	Range	2.53 to 3.11	* to 4.43	3.07 to 3.42	2.42 to 2.82	3.10 to 3.30	2.46 to 2.96	3.10 to 3.48	2.31 to 2.67	3.16 to 4.28	2.89 to 3.32	3.21 to 3.95

* Asterisk denotes that coverage ratio fell below 2.0 in at least one year.

+ This anomaly is well within the margins of error inherent in the computational methodology.

Source: Teknekron, Inc., 1978.

TABLE 7-20

QUALITY OF EARNINGS

--Percentage of Earnings that is Noncash AFDC--
For Investor-Owned Electric Utilities on a Regional Basis
Under Alternative Scenarios, 1985-95

Moderate Growth		Nation	N. Eng.	Mid-Atl.	S.-Atl.	E.N. Central	E.S. Central	W.N. Central	W.S. Central	N. Mtn.	S. Mtn.	Pacific
Baseline	Mean	38%	46%	32%	43%	36%	46%	31%	53%	22%	37%	28%
	Range	35 to 44	39 to 55	30 to 42	39 to 57	35 to 44	38 to 58	28 to 36	39 to 67	12 to 36	29 to 42	27 to 30
80% SO_2 Reduction	Mean	39%	46%	31%	44%	38%	50%	30%	57%	23%	36%	28%
	Range	36 to 47	39 to 55	29 to 35	40 to 58	36 to 46	42 to 61	28 to 35	45 to 71	14 to 30	30 to 43	25 to 31
90% SO_2 Reduction	Mean	40%	44%	31%	45%	38%	50%	30%	57%	24%	37%	28%
	Range	36 to 47	04 to 52	29 to 35	40 to 59	36 to 47	41 to 62	26 to 37	45 to 70	14 to 43	29 to 43	26 to 31
High Growth												
Baseline	Mean	44%	60%	38%	51%	43%	52%	37%	55%	30%	42%	34%
	Range	41-48	52-65	36-41	45-63	41-45	45-61	35-41	43-68	20-38	37-48	33-36
90% SO_2 Reduction	Mean	47%	60%	39%	53%	45%	57%	40%	62%	33%	45%	35%
	Range	43-55	53-66	37-41	47-66	43-47	41-72	37-43	48-72	23-50	39-55	33-37

Source: Teknekron, Inc., 1978.

TABLE 7-21

REGIONAL PRICE IMPACTS ON THE ELECTRIC UTILITY INDUSTRY OF ALTERNATIVE NSPS REVISIONS. 1995

Scenario / Year	MODERATE GROWTH				HIGH GROWTH			
	Baseline[a]		90% SO_2 Reduction		Baseline[a]		90% SO_2 Reduction	
Region	Price 1976*	1995*	1995 Price*	Percent** Increase	Price 1976	1995	1995 Price*	Percent+ Increase
Nation	2.62*	2.93	2.98	1.7	2.62*	3.10	3.26	5.2
N. Eng	3.96	4.23	4.30	1.7	3.96	4.31	4.32	0.2
Mid-Atl.	3.75	3.58	3.65	2.0	3.75	3.83	3.91	2.1
S.-Atl.	2.89	3.03	3.08	1.7	2.89	3.27	3.42	4.6
EN Central	2.56	3.11	3.12	0.3	2.56	3.32	3.48	4.8
ES Central	1.68	1.32	1.35	2.3	1.68	1.42	1.46	2.8
WN Central	2.57	2.73	2.78	1.8	2.57	2.95	3.11	5.4
WS Central	1.99	2.92	3.24	11.0	1.99	2.91	3.26	12.0
N. Mtn.	1.37	2.02	2.09	3.5	1.37	2.30	2.47	7.4
S. Mtn.	2.52	2.67	2.77	3.7	2.52	2.91	2.96	1.7
Pacific	2.11	2.75	2.80	0.7	2.11	2.90	2.93	1.0

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*Prices to retail customers expressed in ¢/kwh, in 1975 dollars. Represents a weighted average of privately and publicly owned utilities.

**Percentage change from Baseline, moderate growth.

+Percentage change from Baseline, high growth.

a - Continuation of present standards 520 ng/J.

Source: Teknekron, Inc., 1978.

calculated by Teknekron. Table 7-21 shows for the nation as a whole and for the 10 regions individually the additional mills per kilowatt-hour which will be paid for electricity in 1995 under the selected scenarios for both high and medium growth rates. The table also shows the percentage increase that each increment represents over the baseline case (no revision in current SO_2 control standard). Tables 7-22 and 7-23 show (for moderate and high growth, respectively) the average additional cost per capita nationally and regionally of the selected alternative revisions of NSPS (based on results for investor-owned utilities).

As can be seen from the tables, most price increments represent small increases on a percentage basis, particularly under the assumption of moderate growth. The price increases projected for the West South Central region (Table 7-21) stand out as relatively very large, more than twice the percentage increase for any other region. Differences among the various scenarios for the moderate growth (shown on a per capita basis in Table 7-22) are slight in most cases. They amount per capita to about \$1 per month maximum on a typical utility fill in the West South Central Region. In the mountain regions, with plentiful supplies of low sulfur coal that can be burned with minimal controls to meet a standard of 220 ng/J (0.5 lb $SO^2/10^6$ Btu), the revision based on such a level without regard to reduction would save some money on electric power compared with 80 and 90 percent reduction scenarios.

TABLE 7-22

PER CAPITA COST OF ALTERNATIVE NSPS REVISIONS FOR INVESTOR-OWNED UTILITIES 1995*

(MODERATE GROWTH IN 1975 DOLLARS)

Region	Baseline Costs[a]	90% SO_2 Reduction	80% SO_2 Reduction	0.5 lb SO_2 Per 10^6 Btu
Nation	$530	$538	538	537
N. Eng.	476	484	477	484
Mid-Atl.	469	474	474	475
S.-Atl.	576	581	582	583
E. N. Central	577	580	582	580
E. S. Central	365	372	372	375
W. N. Central	475	481	481	478
W. S. Central	662	693	691	687
N. Mtn.	426	467	464	451
S. Mtn.	462	476	473	463
Pacific	541	548	549	548

[a] - Assuming continuation of present standards.

*Defined as total revenues divided by population in 1995.

+All figures expressed in 1975 dollars.

Source: Teknekron, Inc., 1978.

TABLE 7-23
PER CAPITA COST OF ALTERNATIVE NSPS FOR INVESTOR-OWNED UTILITIES[a]

(In 1975 Dollars)

Region	HIGH GROWTH	
	Baseline Costs[a] (dollars)	90% SO_2 Reduction (dollars)
Nation	685	715
New England	632	632
Mid-Atlantic	609	621
S. Atlantic	766	806
E. N. Central	747	780
E. S. Central	491	505
W. N. Central	629	659
W. S. Central	801	888
N. Mountain	606	654
S. Mountain	617	622
Pacific	677	683

[a] Defined as total revenues divided by population in 1995.

[b] Continuation of present standards - 520 ng/J (1.2 lb $SO_2/10^6$ Btu).

Source: Teknekron, Inc., 1978.

Percentage per capita price increases are higher for the high growth everywhere (Table 7-23). The percentage differences in the South Atlantic and the Pacific regions are less than 2 percent in all scenarios.

It should be noted that the per capita figures in Tables 7-22 and 7-23 do not distinguish classes of users (e.g., commercial versus residential) or individual establishments served. The dollar values merely represent total cost (nationwide or within each region) divided by the appropriate population estimate for 1995.

The effects of increasing the average price of electricity to the consumer by the amounts projected will be relatively small in terms of the cost of living. A measure of the effect of price of electricity is provided by the weighting attached to this item of expenditure in the Consumer Price Index (CPI) computed periodically by the U.S. Department of Labor, Bureau of Labor Statistics.

> The relative importance of a component of the Consumer Price Index is its expenditure or value weight expressed as a percentage of all items. At the time of their introduction, after a major weight revision, the value weights for groups of commodities represent average annual expenditures of urban wage-earner and clerical worker consumers and relative importances indicate how these consumers actually allocate their expenditures to the various groups (U.S. Department of Labor, 1976).

As of December 1976 (the latest date for which CPI information was available at the time of writing) a weight of 1.367 was assigned to the price of electricity in the CPI on a nationwide basis. This figure reflects the fact that on the average national expenditures for electricity represented 1.367 percent of all consumer expenditures. The CPI is computed by multiplying for each item included the price change (essentially as a percentage basis) of that item by the percentage weight, then summing all of the resultant products and dividing by the base data aggregate. Comparison of the CPI thus obtained for a given month with that computed for a previous time period enables an estimate to be made of increase or decrease in this specific measure of the average cost of living. Each increase of 100 percent in the price of electricity would raise the CPI by 1.367 percentage points. An increase of 2 percent in the price of electricity would be reflected as an increase of about 0.027 percentage points in the CPI.

The relative importance of the cost of electricity to the average consumer may be indicated by comparing the weight of 1.367 with weights of 23.667 for food, 9.194 for apparel and upkeep, 3.206 for gasoline in private transportation and 19.013 for health and recreation (among selected categories of items) (U.S. Department of Labor, 1976).

The CPI is also computed for regions of the country, such as individual Standard Metropolitan Statistical Areas (SMSA). Results for selected SMSAs indicate that price increase in electricity would have somewhat greater impact (percentage-wise) on some localities such as SMSA in Ohio and in the areas of Pittsburgh, Buffalo, Atlanta and Detroit than on the national average. Conversely, in Boston, Seattle, Chicago and Baltimore the percentage impact would be relatively less.

It may also be noted that the cost of electricity (along with that of other items reflecting energy sources) has risen recently. The weight of 1.367 assigned in December 1976 represents an increase of 1.46 percent over the weight of 1.347 assigned in December 1975. In view of the factors that tend to increase energy costs at a rate exceeding price rises in other commodities, it may be conjectured that the weight assigned to electricity in future years will be still higher. However, there is no valid basis for estimating the weight in any future year. Even conjecturing that the relative expenditures for cost of electricity increased annually by 2 percent (the percentage increase noted between 1975 and 1976) would leave the weight assigned for electricity in the CPI at less than 2 by 1995.

7.4.4 Secondary Economic Impacts

7.4.4.1 Economic Impacts on the Coal Industry. Secondary effects of the revised NSPS on the coal industry will be chiefly a slight reduction (over the baseline situation) in the total amount of coal to be produced and a shift in the pattern of regional production.* These effects are shown quantitatively in Table 7-24 for the year 1990.

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*In all situations the total amount of coal produced in the future will be much greater than current production.

TABLE 7-24

1990 COAL PRODUCTION UNDER ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS (ELECTRICITY GROWTH RATE OF 5.8 PERCENT PER YEAR UNTIL 1985 AND 5.5 PERCENT THEREAFTER) (in 10^6 tons)

Region *	1.2 lb $SO_2/10^6$ Btu	90% Removal	INCREMENT IN TOTAL	
			10^6 Tons	Percent
Northern Appalachia				
Low Sulfur	28.0	20.2		
Medium Sulfur	111.2	128.0		
High Sulfur	65.5	109.5		
Total	204.8	257.6	+52.8	+25.8
Central and Southern Appalachia				
Low Sulfur	198.4	176.4		
Medium Sulfur	35.0	32.3		
High Sulfur	3.1	3.1		
Total	236.5	211.8	-51.7	-21.9
Midwest and Central West				
Low Sulfur	2.6	1.6		
Medium Sulfur	97.9	99.7		
High Sulfur	197.5	271.1		
Total	298.0	372.4	+74.4	+25.0
Northern Great Plains				
Low Sulfur	547.3	321.1		
Medium Sulfur	262.0	329.9		
High Sulfur	0.3	0.3		
Total	809.6	651.4	-158.2	-19.5
Rest of West				
Low Sulfur	94.4	79.0		
Medium Sulfur	124.5	138.6		
High Sulfur	-	-		
Total	219.0	217.7	-1.3	-0.6
National				
Low Sulfur	870.6	598.3		
Medium Sulfur	630.8	728.6		
High Sulfur	266.5	384.0		
Total	1,767.9	1,710.8	-57.1	-3.2

* These regions differ from those discussed under costs and prices of electricity in the preceding subsections. The Mountain Region, as used for census purposes, combines the Northern and Southern Mountain Regions used in Teknekron. Low sulfur includes coal that has less than 0.6 lb sulfur per million Btu or is of metallurgical quality. Low sulfur coal can meet the current NSPS of 1.2 lb SO_2 without scrubbers. Medium sulfur coal has between 0.61 and 1.67 lb of sulfur per million Btu or roughly 0.7 to 2 percent sulfur coal. High sulfur coal has above 1.67 lb sulfur or is roughly more than 2 percent sulfur.

Source: ICF, Inc., 1978a.

More stringent control of SO_2 with increased use of FGD systems extracts a penalty in the effective energy output derived from the coal and, hence, more fuel is required to achieve a given level of power production. Surprisingly, for 1990, the 90 percent reduction of SO_2* is predicted to lead to a decrease in the total amount of coal required, from 1,767.9 million tons under current standards to 1,710.8 million in 1990 under the proposed revision. This reduction in tonnage results from two causes. First, imposition of FGD systems under the 90 percent reduction scenario would make it economical to burn more eastern coal that has a higher average btu content than most western coal, consumption of which is accordingly reduced. Average btu content of all coals consumed for power generation, therefore, would increase, requiring a slightly smaller total amount of coal. Secondly, more utility oil and gas is expected to be consumed as higher costs of coal-fired power plants make it economically competitive to increase the use of oil and gas in existing oil and gas steam plants (ICF, Inc., 1978).

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*Projections under the scenarios of 80 percent SO_2 reduction and a maximum emission rate of 0.5 lb $SO_2/10^6$ Btu showed coal production in 1990 differing by less than 1 percent from estimates for 90 percent SO_2 reduction in any of the regions listed in Table 7-24 (ICF, Inc., 1978).

Table 7-24 gives coal production in millions of tons by sulfur content[**] within each region.[***] Noteworthy changes under 90 percent SO_2 control are production increases in high sulfur coal in Northern Appalachia, the Midwest and Central West. The requirement for scrubbers in all new plants would enable higher sulfur coal to be more economically competitive with the transport and use of low sulfur coal. Medium sulfur coal production would also increase, whereas mining of low sulfur coal would decline everywhere. The effects on overall coal production are far more significant regionally than nationally (where the total decrease is only 3.2 percent). As most western coal is low sulfur, the decline there would be over 15 percent or about 160 million tons in 1990. Also, the higher sulfur coals of the Midwest, Central West and Northern Appalachia would be produced in greater quantity; whereas a drop particularly in low sulfur coal production in Central and Southern Appalachia would result in 1990 in an overall decrease of nearly 22 percent (over 51 million tons).

[**] Low sulfur includes coal that has less than 0.6 lb sulfur per million btu or is of metallurgical quality. Low sulfur coal can meet the current NSPS of 520 ng/J (1.2 lb SO_2) without scrubbers. Medium sulfur coal has between 0.61 and 1.67 lb of sulfur per million Btu or roughly 0.7 to 2 percent sulfur coal. High sulfur coal has above 1.67 lb sulfur or is roughly more than 2 percent sulfur. (ICF, Inc.,1978a).

[***] These regions differ from those discussed under costs and prices of electricity in the preceding sections. The Mountain Region, as used for census purposes, combines the Northern and Southern Mountain Regions used in Teknekron calculations.

7.4.4.2 Economic Impacts on Coal Transportation. The proposed revisions of NSPS will considerably alter the pattern of coal transportation. In particular, the amount of western coal shipped to the East is projected to be about 455 million tons in 1990 under continuation of the present 520 ng/J (1.2 lb $SO_2/10^6$ Btu) and slightly under 300 million tons under the requirement for 90 percent SO_2 removal.* There will also be a net decrease in the 90 percent reduction scenario of 226 billion in total ton-miles of coal shipments (i.e., tonnage moved between any two points multiplied by the distance as compared with continuation of present standards). The principal cause of this relative decrease in shipping will be the reduced shipment of western coal to the East. As a result, the average shipment will be 687 miles under 90 percent SO_2 removal, as contrasted with 791 miles if present standards are continued (ICF, Inc., 1978a).

These results are shown quantitatively in Tables 7-25 through 7-28. Table 7-25 gives coal distribution from each of the five production areas or coal supply regions to the nine census regions** for consumption as projected for 1990 under the baseline situation

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*Variations in coal shipment from West to East as projected for scenarios of 80 percent SO_2 reduction and of a maximum emission level of 220 ng/J (0.5 lb SO_2 Btu) differ from those shown in Table 7-28 for the 90 percent reduction scenario by less than 1 percent in 1990.

**These regions differ from those discussed under costs and prices of electricity in the preceding sections. The Mountain Region, as used for census purposes, combines the Northern and Southern Mountain Regions used in Teknekron calculations.

TABLE 7-25

1990 COAL DISTRIBUTION UNDER THE CURRENT NEW SOURCE PERFORMANCE STANDARD OF 1.2 LBS. OF SO_2 (HIGH ELECTRICITY GROWTH RATE)
(in 10^6 tons)

	Coal Supply Regions							
Consuming Regions	Northern Appalachia	Central and Southern Appalachia	Midwest and Central West	Total East	Northern Great Plains	Rest of West	Total West	National*
New England	19.3	0.9	-	20.2	0.2	-	0.2	20.4
Middle Atlantic	104.7	25.4	-	130.1	62.2	-	62.2	192.3
South Atlantic	51.7	119.5	32.9	204.1	107.7	-	107.7	311.7
East North Central	28.6	68.2	172.5	269.7	170.4	14.1	184.5	453.8
East South Central	-	21.5	62.1	83.6	99.8	0.9	100.7	184.3
Total East	204.3	235.6	267.5	707.3	441.3	15.0	455.3	1,162.5
West North Central	-	0.9	24.4	25.3	140.4	7.7	148.1	173.5
West South Central	-	0.3	5.6	5.9	89.5	126.2	215.8	221.6
Mountain	-	-	-	-	108.6	46.1	154.7	154.7
Pacific	-	-	0.4	0.4	30.7	21.2	52.0	52.3
Total West	-	1.2	30.4	31.6	369.2	201.3	570.6	602.1
National*	204.3	236.5	297.0	737.8	810.6	215.4	1,026.0	1,764.6

*Subject to small round-off error in the decimal fraction.

Source: ICF, Inc., 1978a.

TABLE 7-26

1990 COAL DISTRIBUTION UNDER AN ALTERNATIVE NEW SOURCE PERFORMANCE STANDARD OF 90 PERCENT REMOVAL OF SO_2 (HIGH ELECTRICITY GROWTH RATE)
(in 10^6 tons)

(Compared with Distribution Under Present Standards)

Consuming Regions	COAL SUPPLY REGIONS															
	Northern Appalachia		Central and Southern Appalachia		Midwest and Central West		Total East		Northern Great Plains		Rest of West		Total West		National*	
	Tonnage	Increment+	Tonnage	Increment+	Tonnage	Increment+	Tonnage	Increment+	Tonnage	Increment+	Tonnage	Increment+	Tonnage	Increment+	Tonnage	Increment+
New England	19.8	0.5	0.9	0	-	0	20.8	+0.6	-	-1.2	-	0	-	-1.2	20.8	-0.6
Middle Atlantic	115.3	+10.6	23.1	-2.3	-	0	138.4	+8.3	18.0	-44.2	-	0	18.0	-44.2	156.4	-35.9
South Atlantic	91.5	+39.8	106.3	-18.9	38.1	+24.0	249.0	+44.9	64.3	-43.4	-	0	64.3	-43.4	313.3	-1.6
East North Central	30.7	+2.1	58.2	-10	196.9	+25.2	285.7	+17.2	133.4	-37.0	11.7	-2.4	145.2	-39.3	430.9	-22.1
East South Central	-	0	21.5	0	84.9	+22.8	106.4	+22.8	69.9	-29.9	0.9	+0.9	70.8	-29.0	177.2	-6.2
Total East	257.3	+53.0	210.0	-31.2	319.9	+72.0	800.3	+93.8	285.6	-155.7	12.6	-1.5	298.3	-157.1	1,098.6	-63.3
West North Central	-	0	0.9	0	26.5	+0.3	27.4	+0.3	141.6	+1.2	0.5	-7.2	142.1	-6.0	169.5	-5.8
West South Central	-	0	0.9	+0.9	6.7	+2.9	7.6	+3.8	89.5	0	131.4	+5.2	221.0	+5.2	228.6	+9.1
Mountain	-	0	0.7	+0.1	-		0.1	+0.1	107.4	-1.2	48.3	+2.2	155.6	+0.9	155.7	+1.0
Pacific	-	0	-	0	0.3	-0.1	0.3	-0.1	26.7	-4.0	24.3	+3.1	51.0	-1.0	51.4	-0.9
Total West	-	0	2.5	+1.0	33.5	+3.1	35.4	+4.1	365.2	-4.0	204.5	+3.3	569.7	-0.9	605.2	+3.4
National*	257.3	206.3	206.2		372.3		835.8		650.9		217.1		868.0		1,703.8	-59.9

*Subject to small round-off error in the decimal fraction.

+Increase or decrease in millions of tons compared to baseline as given in Table 7-19.

Source: ICF, Inc., 1978a.

(continuation of current standards). Table 7-26 shows the same interarea distribution as projected for 1990 under the assumption of 90 percent SO_2 removal, together with the increase or decrease in coal shipped from each supply region to each consuming region as contrasted with the baseline situation. Ton-mile shipments between East and West are contrasted under the two scenarios in Tables 7-27 and 7-28.

As seen in Table 7-27, the West is projected in the baseline situation to ship coal it has produced a total of nearly 700 billion ton-miles in the East and over 400 billion ton-miles to points for consumption in the West. Conversely, the East is estimated (under continuation of present NSPS) to ship its coal product for use in the West, a total of only 11 billion ton-miles; whereas coal both produced and burned in generating electric power in the East will move a total of 266 billion ton-miles. Coal consumed in the East will (wherever it is produced) represent a movement of nearly 1 trillion ton-miles (as shown in the last column of Table 7-27). The changes reflected under the 90 percent SO_2 reduction as shown in Table 7-28 are almost entirely due to the decreased shipment of western coal. Coal burned in producing electric power in the East will represent a drop in shipment of over a quarter of a trillion ton-miles. Changes from the baseline scenario in the shipment of coal for generation of electric power in the West will be negligible. Total movement of

TABLE 7-27

1990 TON-MILES OF COAL SHIPMENTS UNDER THE CURRENT NEW SOURCE PERFORMANCE STANDARD OF 1.2 LBS. OF SO_2 (HIGH ELECTRICITY GROWTH RATE) (in 10^9 ton-miles)

Consuming Regions	Producing Regions		
	East	West	National
East	266	699	965
West	11	420	431
National	277	1,119	1,396

Average ton moves 791 miles.

Source: ICF, 1978a.

TABLE 7-28

1990 TON-MILES OF COAL SHIPMENTS UNDER AN ALTERNATIVE NEW SOURCE PERFORMANCE STANDARD OF 90 PERCENT REMOVAL OF SO_2 (HIGH ELECTRICITY GROWTH RATE) (in 10^9 ton-miles)

Consuming Regions	Producing Regions		
	East	West	National
East	300	443	743
West	12	415	427
National	312	858	1,170

Average ton moves 791 miles.

Source: ICF, 1978a.

coal in ton-miles to the West from anywhere in the nation is projected to drop by less than 1 percent.

7.4.4.3 Effect on Coal Mining Employment

Total production of coal for use in generation of electricity will of course increase substantially by 1990, but the increase under 90 percent SO_2 reduction will be slightly less than that projected under maintenance of current NSPS. Thus, the effect is a net decrease under the revised NSPS when compared to the baseline. However, the requirement for miners is projected to increase in all situations. Under 90 percent reduction a rise in employment (over the baseline situation) would result because much more eastern coal would be mined and less western coal. The mines of the west can be operated at a higher rate of production per miner. Table 7-29 contrasts 1990 projected employment requirements for the five coal production regions under the baseline situation (no change from current standards of 520 ng/J) and the proposed NSPS for 90 percent removal.

Major employment increases in Northern Appalachia the Midwest, and the Central West would not be fully offset by decreases in Central and Southern Appalachia and in the Great Plains. The rest of the West is relatively unaffected. The net increase projected to occur over actual employment figures for 1975 is also shown in Table 7-29. As can be seen, the work force needed to produce coal in Central and Southern Appalachia for generating electric power is expected to remain nearly stable (about 1 percent increase in the 90 percent

TABLE 7-29

COAL INDUSTRY EMPLOYMENT* (IN THOUSANDS OF EMPLOYEES)

ELECTRICITY GROWTH RATE OF 5.8 PERCENT PER YEAR UNTIL 1985 AND 5.5 PERCENT THEREAFTER

Region	1975 Actual	1990		Net Changes Baseline	
		1.2 lbs. SO_2+	90% Removal	Increment	Percent
Northern Appalachia	59.1	67.3	88.9	+21.6	29.8
Central and Southern Appalachia	91.6	104.0	93.2	-10.8	1.6
Midwest and Central West	29.7	64.9	82.5	+17.6	52.8
Northern Great Plains	2.8	26.4	20.3	-6.1	17.5
Rest of West	6.7	23.1	22.7	-0.4	16.0
National	189.9	285.7	307.6	+21.9	117.7

*Miners and mine supervisors, exclusive of employees at mining company headquarters and of workers in coal preparation plants.

+ - Baseline

Source: ICF, Inc., 1978a.

reduction scenario over 1975); whereas huge increases are projected for all other production regions. The net gain in employment will greatly exceed the 1975 work force in all regions except Appalachia. Employment is projected to increase in the Great Plains by a factor of 8.42 in the baseline situation and of 6.25 in the 90 percent reduction scenario.

The further impacts generated by this overall increase in employment and by the changes in distribution of the labor force are difficult to predict and certainly cannot be accurately quantified.

In classical economics, jobs are not created but filled at the expense of jobs elsewhere. But many examples can be cited to indicate such a theory represents a drastic oversimplification, and that its resulting assumptions, particularly about the mobility of the labor force, may be at variance with prevailing conditions. However, it is true that coal mining is a specialized occupation requiring skills that may not be possessed by those unemployed.

Some indication of the immediate follow-on effects of this shift in employment may be seen from the changes in the total payrolls to coal miners as given in Table 7-30. Coal mine payrolls will be greater in the Northeast and Midwest by the amounts shown than they would otherwise have been, whereas coal mine payrolls will be reduced in the West and in Central and Southern Appalachia. These potential losses may or may not be compensated by other sources of income. Changes in the induced effects resulting from employment

TABLE 7-30

ESTIMATED REGIONAL INCOME DIFFERENTIAL IN 1990 RESULTING FROM 90 PERCENT SO_2 REDUCTION

(from coal mining)

	REGIONS									
	Northern Appalachia		Central and Southern Appalachia		Mid and Central West		Great Plains		Rest of West	
	Factors	Dollar Value (Millions)	Factors	Dollar Value (Millions)	Factors	Dollar Value (Millions)	Factors	Dollar Value (Millions)	Factors	Dollar Value (Millions)
1. Coal Mine Employee Differential	+21,600	-	-10,800	-	+17,600	-	-6,100	-	-400	-
2. Average Annual Wage Per Worker*	-	.019	-	.018	-	.019	-	.022	-	.022
3. Value of Payroll Affected [a]	-	+410.4	-	-194.4	-	+334.4	-	-134.2	-	8.8
4. Regional Multiplier	2.9	-	2.5	-	2.8	-	2.1	-	2.1	-
5. Indirect and Induced Income [b]	-	+1,190.2	-	-486.0	-	+936.3	-	-281.8	-	18.5
6. Total Dollar Value Based on Lost [c]		+1,600.6		-$680.4		+$1,270.7		-$416.0		-$27.3

*In 1975 dollars. Wages are estimated to at a ratio over inflation at a rate of 1.4048 for the 15-year period, 1975-1990.

[a] Line 1 column 2 x line 2 column 1

[b] Line 4 column 1 x line 3 column 2

[c] Line 3 + line 5

SOURCES: University of Montana, Bureau of Business and Economic Research, Projections of Economic Development Associated with Coal-Related Activity in Montana. Missoula, Montana, January, 1974.

United States Department of Commerce, Bureau of the Census, City and County Data Book, 1967. U. S. Government Printing Office, Washington, D. C.

United States Department of Commerce, Bureau of Economic Analysis. Computer printout of industrial multipliers, 1976.

United States Department of Labor, Bureau of Labor Statistics, Employment and Earnings, August 1976. U. S. Government Printing Office, Washington, D. C.

shifts appear in Table 7-30. Induced effects result from the fact that money provided to workers (and similarly for other production costs) creates a demand for additional goods and services. For example, housing must be provided; retail sales increase in the area when coal mines expand; new stores, restaurants, and other businesses move in; and service activities produce induced income.

To the extent that a revised NSPS of 90 percent SO_2 removal would increase mining employment in regions with traditionally high production of coal and decrease it in the West, the socioeconomic consequences may be less than would result by maintaining the current standards. In 1975, mining employment in the West represented only about 5 percent of the national total. This small fraction of the total western labor force is projected to increase more than fivefold by 1990 under the baseline scenarios. Much of the western coal lies in localities where very little mining has occurred in the recent past and is not part of the way of life. Communities there lack infrastructures for dealing with large influxes of miners and with the secondary growth associated that can create boom towns in farming and ranching communities.

Mine employment in the West is projected to grow in any event by over 30,000 workers in 1990. Therefore, it is far from clear what differences in sociologic conditions would occur if this labor force does not increase by a further 6500 miners. It can be noted, however, that such regions find their problems of adjusting to industrial growth increasingly complicated as the size of the outside work force grows. The rate of financial growth in the West may (as implied by Table 7-30) be somewhat slowed under 90 percent SO_2 reduction; however, the resulting socioeconomic problems are likely to be diminished. Eastern coal regions would of course face increased socioeconomic problems as the labor force grows more under the 90 percent reduction scenario than in the baseline situation. However, the increase, even though sizable, will represent a much smaller percent of the 1975 base. The eastern regions can also be expected to have an advantage in dealing with the growth because coal mining in these locations has long been a way of life. However, many other economic and sociologic variables will strongly influence the extent of impacts experienced.

7.4.4.4 Plant Construction. Increased installation of FGD systems under the revised NSPS will have a significant economic impact through the direct and indirect effects resulting from the additional employment.

The average numbers of man-years of construction forces required to build power plants under existing and proposed revisions to NSPS have been calculated by PEDCo (1977c). The work force required varies somewhat with the size of the plant; economies of scale are possible so that as the rated capacity of the plant increases, the ratio of man-years to MWe decreases slightly. For the 600 MWe-plant (the size modeled in the Teknekron simulations discussed in Section 7.4), the work force requirement is slightly over 1.1 man-year per MWe. Specifically, the estimates (expressed in gigawatts) are as follows (PEDCo, 1977).

Scenario*	Man-Years per GW
Current NSPS (Baseline)	1150
90 Percent SO_2 Reduction	1170
220 ng/J (0.5 lb $SO_2/10^6$ Btu)	1186

Using these figures, the incremental man-years required under 90 percent SO_2 reduction and under a ceiling of 220 ng/J (0.5 lb SO_2 $/10^6$ Btu) (compared with baseline) were calculated together with the resulting additional payrolls and secondary income. The gigawatt capacities projected as requiring FGD at 5-year intervals under baseline and under the alternative scenarios were taken from Teknekron calculations as shown in Table 7-31.

Results of calculating additional payroll and secondary income under revised NSPS are shown in Table 7-32 for the moderate growth rate and in Table 7-33 for the high growth rate. It was assumed that the 1980 capacity with FGD was the same in all scenarios, as capacity affected by revised NSPS would probably not be operational until after that date. Results for the moderate growth scenarios are straightforward. These figures show the additional income generated under the 220 ng/J (0.5 lb $SO_2/10^6$ Btu) scenario to be on the order

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*Calculations for 80 percent reduction were not reported.

TABLE 7-31

REQUIRED CAPACITY OF ELECTRIC POWER WITH FGD SYSTEMS

Scenario	GW CAPACITY WITH FGD 1985	1990	1995
Moderate-Growth Baseline			
Maintenance of Present NSPS	52.5	61.3	67.1
90% SO_2 Reduction	74.2	145	207
Increment Over Baseline	21.7	83.7	139.9
0.5 lb $SO_2/10^6$ Btu	71.3	132	188
Increment Over Baseline	18.8	70.7	120.9
High-Growth Baseline			
Maintenance of Present NSPS	45.6	59.4	76.5
90% Reduction	65.0	216	403
Increment Over Baseline	19.4	156.6	326.5

Source: Teknekron, Inc., 1978.

of 1 3/4 times as great as that under 90 percent reduction. Total additional income generated (over baseline) will exceed $100 million during the period 1990-1995.

The high growth situation introduces a slight complication as may be seen in Table 7-33. A study of firms providing FGD systems showed that at present industry would be capable of installing all of the capacity required under any of the scenarios except that of high growth with 90 percent SO_2 reduction. For this situation substantial staff increases would be required. It was, therefore, assumed that employment in the FGD industry itself (not included in the PEDCo study of construction forces required for power plants) would be essentially the same for all scenarios under moderate growth. Significant additional employment was assumed for the scenario of high growth with 90 percent SO_2 reduction, according to Tables 7-34 and 7-35. Table 7-34 indicates significant employment increases that would be necessary within the industry to meet FGD requirements. These amount to slightly over 12 man-years per additional MWe capacity, derived from estimates obtained in an industry survey (IGC, Inc., 1977). The distribution of additional manpower by type of employee is shown in Table 7-35. These basic figures have been incorporated into the employment estimates for the 90 percent reduction scenario under high growth in Table 7-33. Average annual pay for craftsmen is assumed to be the same as that for the construction worker. Medium income for the other employee types was calculated in

TABLE 7-32

ADDITIONAL INCOME RESULTING FROM INCREASED EMPLOYMENT IN POWER PLANT CONSTRUCTION WITH FGD SYSTEMS
MODERATE GROWTH RATE OF POWER

	1980 - 1985				1985 - 1990				1990 - 1995			
	90% Reduction		0.5 LB SO_2		90% Reduction		0.5 LB SO_2		90% Reduction		0.5 LB SO_2	
	Factors	Millions of Dollars[c]	Factors	Millions of Dollars	Factors	Millions of Dollars[c]	Factors	Millions of Dollars[c]	Factors	Millions of Dollars[c]	Factors	Millions of Dollars
Additional GW over Baseline[a]	21.7		18.8		62		51.9		56.3		50.2	
Additional Construction Force												
- Man-years	434		752		1240		2076		1124		2008	
- Average pay per man-year (thousands of dollars)	13.793		13.845		15,9		15.9		19.34		19.34	
- Additional payroll		5.986		10.411		19.716		33.008		21.738		38.835
Industrial Multiplier[b]	2,713		2.713		2.713		2.713		2.713		2,713	
Secondary Income		16.241		28.245		53.490		89.551		58.975		105.360
Total Increment over Baseline		22.277		38.656		73.206		122,559		80.713		144.195

a - GW capacity requiring FGD systems additional to that required under maintenance of current NSPS.
b - Represents the additional income generated over and above that supplied directly by the industrial payroll.
c - Converted to 1975 dollars.

Source: U.S. Department of Commerce, 1976. U.S. Department of Commerce, 1974. IGCI, Inc., 1977. PEDCo, 1977c.

TABLE 7-33

ADDITIONAL INCOME RESULTING FROM INCREASED EMPLOYMENT IN POWER PLANT CONSTRUCTION WITH FGD SYSTEMS HIGH GROWTH RATE OF POWER AND 90% SO_2 REDUCTION

	1980 - 1985		· 1985 - 1990		1990 - 1995	
	Factors	Millions of 1975 Dollars	Factors	Millions of 1975 Dollars	Factors	Millions of 1975 Dollars
Additional GW over Baseline[a]	19.4		137.2		169.9	
Additional Construction Force						
- Man-years	388		2744		33.9	
- Pay per man-year[c]	13.793		15.9		19.34	
- Additional pay-roll		5.352		43.630		65.717
Additional FGD Industry Staff						
● GW Capacity Affected[d]	0		68		193	
● Employee Type						
Engineers and Designers						
- Man-years			155		440	
- Median pay per man-year[c]			27.29		33.2	
- Additional payroll				4.230		14.608
Craftsmen						
- Man-years			611		1733	
- Median pay per man-year[c]			15.9		19.34	
- Additional payroll				9.715		32.356
Administrative						
- Man-years			52			
- Median pay per man-year[c]			12.48		15.18	
- Additional payroll				0.649	149	2.262
Total Additional Payroll		5.352		58.224		114.936
Industrial Multiplier[b]	2.713		2.713		2.713	
Secondary Income		14.519		157.962		311.821
TOTAL INCREMENT OVER BASELINE		19.871		216.186		426.757

a - GW capacity requiring FGD systems additional to that required under maintenance of current NSPS.

b - Represents the additional income generated over and above that supplied directly by the industrial payroll.

c - In thousands of 1975 dollars.

d - Increment above the stated capacity that can be supplied with no significant staff increases by the industry (as given in Table 7-34).

Source: U.S. Department of Commerce, 1976. U.S. Department of Commerce, 1974. IGCI, Inc., 1977. PEDCo, 1977c.

TABLE 7-34

INDUSTRY CAPACITY TO MEET FGD REQUIREMENTS
(High Growth Rate, 90 Percent SO_2 Reduction)

	CUMULATIVE CAPACITY IN GW PROVIDED WITH FGD		
YEAR	FGD INDUSTRY WITH[a] PRESENT STAFF	PROJECTED REQUIREMENTS[b]	SHORTAGE AT END OF 5-YEAR PERIOD
1982	51.4	(c)	-
1985	87[d]	64.4	(c)
1987	110.85	123[d]	-
1990	148[d]	216	68
1992	173.15	(c)	-
1995	210[e]	403	183

[a] Teknekron, 1978.

[b] Industrial Gas Cleaning Institute, Inc., 1977.

[c] Not given by source.

[d] Interpolated.

[e] Exprapolated.

the same way from income data in the Statistical Abstract of the United States.

7.4.4.5 Increased Consumption of Oil and Gas. A revised NSPS is projected to increase the costs of burning coal for generation of electricity. Consequently, oil and gas will be economically more attractive as a fossil fuel than they would otherwise be, i.e., under maintenance of the current standards of 520 ng/J (1.2 lb $SO_2/10^6$ Btu).

TABLE 7-35

DISTRIBUTION OF FGD INDUSTRY EMPLOYMENT
PER GW REQUIRED FOR INSTALLATION OF ADDITIONAL FGD EQUIPMENT

EMPLOYEE	MAN-YEARS PER GW
Designers	1.0
Engineers	1.28
Craftsmen	8.98
Administrative	0.77
TOTAL	12.03

Source: IGC, Inc., 1977.

This situation could lead to increased imports of petroleum products (as much as the equivalent of about 550,000 barrels of oil per day by 1995)[*] as discussed in the following paragraphs. Such an outcome is predicted in one analysis of the economic effects of revised NSPS (ICF, Inc., 1978b). Increased petroleum imports to meet the need would adversely affect U.S. balance of payments in foreign trade and would exacerbate competition for increasingly scarce derivatives of petroleum, especially if a sudden shortage should develop, such as that resulting from the Arab oil embargo of 1973.

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[*] This quantity barrels of oil per day represents approximately 0.7 percent of projected U.S. energy demand in 1995 and about 1.7 percent of estimated domestic fossil energy production for the same year. (The Nation's Energy Future, Report to the President by the Ray Committee, 1 December 1973).

Scrubber requirements result in higher capital costs for burning coal.

> The effect of increasing the costs of burning coal is to increase the minimum capacity factor at which it is economic (in terms of minimizing generation costs) to build and operate a new coal plant... The higher capital costs (as a result of the scrubber requirement) would have to be allocated over more kilowatt hours to maintain the same total generation costs (i.e., capital plus operating plus fuel costs), where the breakeven total generation costs between coal and oil would be set by the cost of burning oil in existing steam plants and new turbines (which does not change as a result of the alternative NSPS). This results in a) less coal capacity constructed, b) this coal capacity being operated at higher capacity factors, c) existing oil and gas steam capacity being utilized at higher capacity factors (and hence burning more oil), and d) more turbines being built to satisfy daily and seasonal peak load requirements that would have been provided by existing oil and gas steam plants. (ICF, Inc., January 6, 1978).

Estimates of the amount of oil and gas consumed at 5-year intervals under the alternative NSPS for both moderate and high growth rates of energy appear in Table 7-36. These estimates are based on scenarios in which power generation grows at the rates and with the distribution shown in Table 7-37. Each alternative NSPS can be seen to result in decreased generation of electric power from coal and

TABLE 7-36

UTILITY OIL AND GAS CONSUMPTION
10^{15} Btu (Quads)[a]

	Reference Case I[b]				Reference Case II[c]			
Year	1.2 lb	90%	80%	0.5 lb	1.2 lb	90%	80%	0.5 lb
1975	6.5	-	-	-	6.5	-	-	-
1985	8.2	8.6	8.7	8.7	8.2	8.6	8.1	8.7
1990	5.8	6.4	6.2	6.4	6.4	7.1	7.1	7.1
1995	5.2	6.1	5.9	5.9	7.2	8.3	8.2	8.3

[a] One quad is equivalent to approximately 5 x 10^5 bbl/day of oil.

[b] Assumes growth rate of 5.8 percent per year 1975-85 and 3.4 percent thereafter.

[c] Assumes growth rate of 5.8 percent per year 1975-85 and 5.5 percent thereafter.

Source: ICF, Inc., 1978b.

increased generation from methods using oil and/or gas (ICF, Inc., 1978b).

The results calculated in Table 7-36 reflect scenarios in which new oil-fired plants such as those using a combined cycle are prohibited for nonpeaking purposes, except in Southern California where they are assumed permitted for environmental reasons. The use of combined-cycle operation would have resulted in even more oil consumption. It should be noted that a 1976 study using the PIES model of the Federal Energy Administration predicted that the use of combined cycle operation under standards requiring 90 percent SO_2 reduction would increase oil consumption by as much as 1 million barrels per day (ICF, Inc., 1978b). It should also be noted that the projections in Table 7-37 differ from those shown in Table 7-2. As discussed below, the projections in Table 7-37 are based on an assumption that the generation of power from nuclear sources will remain constant under all scenarios.

As seen from Table 7-36, the alternative NSPS are projected as increasing oil and gas consumption for power generation by 0.2 quads (about 10^5 barrels per day of oil) in 1985. Thereafter, the increase varies with the scenario. In 1990 the range is projected as the equivalent of 200,000 barrels per day for the 80 percent reduction scenario under an assumption of moderate growth to 350,000 barrels per day with a high rate of energy growth. In 1995 the additional consumption ranges from about 350,000 barrels per day (for 80 percent

TABLE 7-37

1990 GENERATION CAPACITY (GW)

	REFERENCE CASE I[a]			
	1.2 LBS $SO_2/10^6$ BTU	90%	80%	0.5 LBS $SO_2/10^6$ BTU
Nuclear	176.7	176.7	176.7	176.7
Coal	395.9	379.0	384.5	378.1
Oil/Gas				
Steam	143.0	143.0	143.0	143.0
Combines Cycle	12.1	11.6	12.2	12.2
Turbine	118.6	136.3	129.8	136.8
Hydro and Others	85.9	85.4	85.8	85.1
Total	932.3	931.9	932.0	931.9
Coal as % of Total	42.5	40.7	41.3	40.6
	REFERENCE CASE II[b]			
	1.2 LBS $SO_2/10^6$ BTU	90%	80%	0.5 LBS $SO_2/10^6$ BTU
Nuclear	176.7	176.7	176.7	176.7
Coal	465.0	444.6	444.3	444.5
Oil/Gas				
Steam	143.6	143.5	143.5	143.5
Combines Cycle	15.9	15.9	15.9	15.9
Turbine	142.5	164.8	163.9	164.4
Hydro and Others	87.6	86.4	86.8	86.2
Total	1030.9	1031.3	1031.1	1031.2
Coal as % of Total	45.0	43.1	43.1	43.1

[a] Assumes growth rate of 5.8 percent 1975-85, 5.5 percent thereafter.
[b] Assumes growth rate of 5.8 percent 1975-85, 3.4 percent thereafter.

Source: ICF, Inc., 1978b.

TABLE 7-38

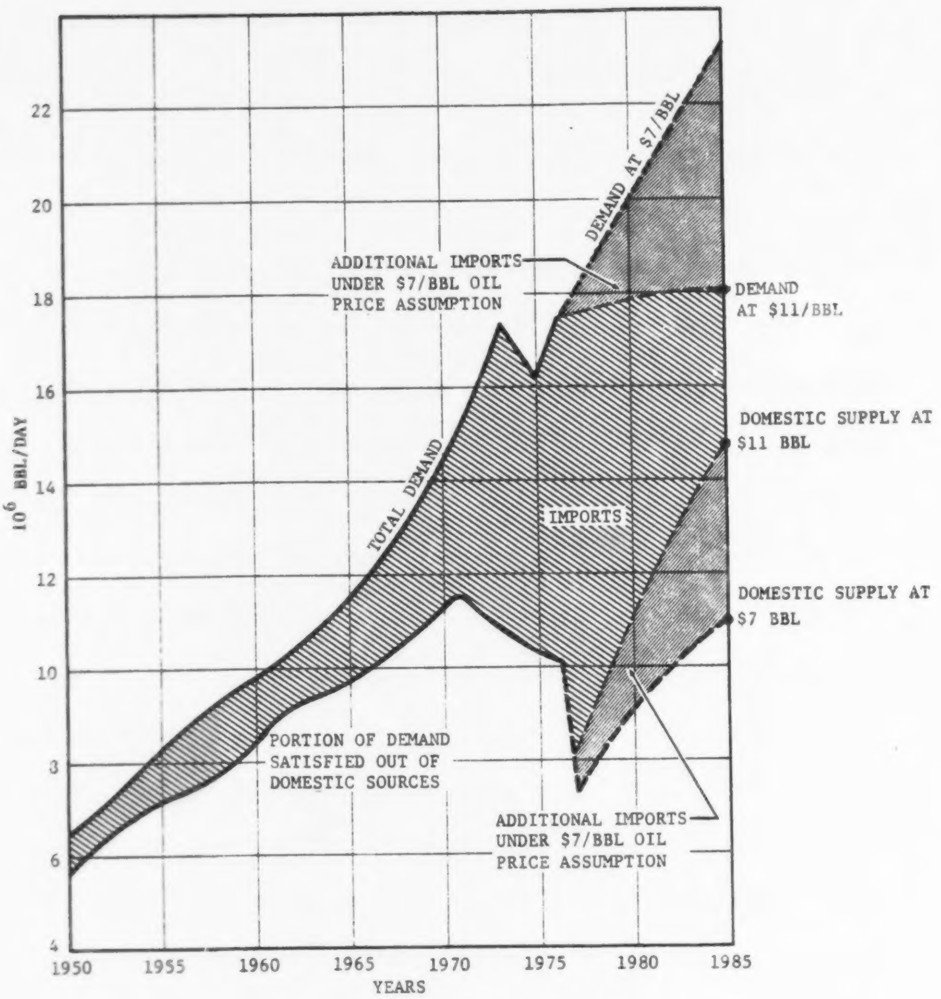
THE SHARE OF IMPORTS IN U.S. DOMESTIC PETROLEUM DEMAND
(Thousands of Barrels)

YEAR	U.S. IMPORTS ANNUAL TOTAL	U.S. IMPORTS DAILY AVERAGE	IMPORTS AS A % OF DEMAND
1947	159,389	437	8.0%
1948	188,144	514	8.9
1949	235,559	645	11.1
1950	310,261	850	13.0
1951	308,194	844	11.9
1952	348,507	952	13.1
1953	377,499	1,034	13.6
1954	383,955	1,052	13.5
1955	455,564	1,248	14.7
1956	525,591	1,436	16.3
1957	574,589	1,574	17.8
1958	620,589	1,700	18.6
1959	649,583	1,780	18.7
1960	664,111	1,815	18.5
1961	699,666	1,917	19.2
1962	759,793	2,082	20.0
1963	774,713	2,123	19.8
1964	826,736	2,259	20.5
1965	900,772	2,468	21.4
1966	939,162	2,573	21.3
1967	925,991	2,537	20.2
1968	1,039,369	2,840	21.2
1969	1,155,551	3,166	22.4
1970	1,248,062	3,419	23.3
1971	1,432,880	3,926	25.8
1972	1,735,314	4,741	29.0
1973	2,283,493	6,256	36.1
1974	2,230,947	6,112	36.7
1975[a]	2,210,335	6,056	37.2
1976[b]	2,669,929	7,295	41.8

[a] Revised

[b] Preliminary

Source: U.S. Bureau of Mines, 1976.



Sources: U.S. Bureau of Mines Petroleum Statement, Annual and December.

American Petroleum Institute, Basic Petroleum Data Book. Washington, D.C. October 1976.

Federal Energy Administration, Project Independence Blueprint, "Project Independence" (Title of Volume), November 1974, pages 23 and 48.

U.S. Energy Research and Development Administration, Final Environmental Impact Statement, Alternative Fuels Demonstration, Vol. I, 1977.

FIGURE 7-6
ACTUAL AND PROJECTED PETROLEUM DEMAND
AND DOMESTIC PRODUCTION
(1950-1985)

reduction under moderate growth) to some 550,000 barrels per day (for high growth with 90 percent reduction or with a ceiling of 220 ng/J 0.5 lb $SO_2/10^6$ Btu.

The above results do not take into account the user taxes and rebates to stimulate use of coal and nuclear generation instead of oil and gas as proposed recently in the President's National Energy Plan (U.S. Congress, 1977). An assessment of the effects of this program indicates that under continuation of the present standards the proposed program of taxes and rebates could save an additional 450,000 barrels per day compared with the quantity used under 90 percent SO_2 reduction (ICF, Inc., 1978).

It is likely that any sizable increase in requirements for oil and gas would be met through foreign imports. The U.S. shortfall in domestic production required to meet demand (Table 7-38) has increased from about 8 percent in 1947 to over 41 percent in 1976. The need for imported petroleum is projected to grow even more in the period to 1995 (Figure 7-6). Of course it is possible that by 1995 synthetic fuels from coal may be available for generation of electricity. But it should be noted that the projections of power generation are based on an assumed price of petroleum with which synthetic fuels are unlikely to be economically competitive. Introduction of synthetic fuels as a source of electric power generation would change the estimates of power generation from coal as well as oil and gas.

Actual and projected costs of imported petroleum products (expressed in dollars per barrel of oil equivalent) are shown in Table 7-39. Total expenditures for the projected increase in imported petroleum products for key years of the 5-year intervals under each scenario appear in Table 7-40.

If not obtained through input of additional foreign petroleum products, the increased gas and oil consumed would be in competition with other uses such as #2 heating oil for residences and commercial establishments. Again the assumption of synthetic fuels from coal could change the picture.

It should be noted that the ICF results were calculated under scenarios in which the contribution of nuclear sources to total power generation was held constant. The projections by ICF (1978) in the 90 percent reduction scenario of 31 percent power generation from oil and gas and 17 percent from nuclear are very nearly a reversal of the percentages of 20 and 35 percent, respectively, calculated by Teknekron (1978) under the assumption that nuclear contribution was not held constant. But it is not necessarily a valid inference from this fact that increased use of nuclear sources would obviate the need for additional power generation using oil and gas. "Most studies show nuclear trading off with coal in baseload and coal trading off with oil in intermediate load, but not nuclear trading off with oil" (ICF, Inc., 1978b). The assumptions used in the two

TABLE 7-39

IMPORTS - PETROLEUM PRODUCTS AND NATURAL GAS

YEAR	VALUE ($ BILLIONS)	NET DEFICIT BALANCE ($ BILLIONS)
1965	2.2	- 1.7
1967	2.5	- 1.6
1969	2.8	- 2.2
1970	3.0	- 2.3
1971	3.6	- 2.8
1972	4.7	- 3.9
1973	7.9	- 7.1
1974	2.4	-23.4
1975 (1st qtr.)	6.4	- 6.2

Source: U.S. Department of Commerce, 1974.

TABLE 7-40

ESTIMATED INCREASED IMPORT COSTS

	REFERENCE CASE I[a]				REFERENCE CASE II[b]		
	BASELINE (1.2 lbs SO_2/10^6 BTU)	INCREMENTS REQUIRED OVER BASELINE			BASELINE (1.2 lbs SO_2/10^6 BTU)	INCREMENT OVER BASELINE	
		90% SO_2 REDUCTION	80% SO_2 REDUCTION	0.5 lbs SO_2/10^6 BTU		90% REDUCTION OR 0.5 lbs SO_2/10^6 BTU*	80% SO_2 REDUCTION
1985							
Additional Oil (Quads)	8.2	0.4	0.5	0.5	8.2	0.4	0.5
Additional Barrels/Year[c]	1,480	72	90	90	1,480	72	90
Annual Increased Costs at $7 per Barrel[d]	$10,360	$ 504	$ 630	$ 630	$10,360	$ 504	$ 630
Annual Increased Costs at $11 per Barrel[d]	$16,280	$ 792	$ 990	$ 990	$16,280	$ 792	$ 990
1990							
Additional Oil (Quads)	5.8	0.6	0.4	0.6	6.4	0.7	0.7
Additional Barrels/Year[c]	1,050	108	72	108	1,158	126	126
Annual Increased Costs at $7 per Barrel[d]	$ 7,350	$ 756	$ 504	$ 756	$ 8,106	$ 882	$ 882
Annual Increased Costs at $11 per Barrel[d]	$11,550	$1,188	$ 792	$1,188	$12,738	$1,386	$1,386
1995							
Additional Oil (Quads)	5.2	0.9	0.7	0.7	7.2	1.1	1.0
Additional Barrels/Year[c]	940	163	126	126	1,300	200	180
Annual Increased Costs at $7 per Barrel[d]	$ 6,580	$1,141	$ 882	$ 882	$ 9,100	$1,400	$1,260
Annual Increased Costs at $11 per Barrel[d]	$10,340	$1,793	$1,386	$1,386	$14,300	$2,200	$1,980

[a] Assumes growth rate of 5.8 percent per year 1975-1985 and 3.4 percent thereafter.

[b] Assumes growth rate of 5.8 percent per year 1975-1985 and 5.5 percent thereafter.

[c] Millions of barrels.

[d] Millions of dollars.

*Identical results for these two alternatives under assumptions of higher growth rate.

Source: ICF, Inc., 1978b.

TABLE 7-41

U.S. BALANCE OF FOREIGN TRADE (1969-1973)

YEAR	VALUE OF TOTAL EXPORTS ($ BILLIONS)[a]	VALUE OF TOTAL IMPORTS ($ BILLIONS)	VALUE OF EXPORTS MINUS VALUE OF IMPORTS ($ BILLIONS)
1960	20.58	15.02	5.56
1961	21.00	14.71	6.29
1962	21.70	16.38	5.32
1963	23.35	17.14	6.21
1964	26.50	18.68	7.82
1965	27.48	21.37	6.11
1966	30.32	25.54	4.78
1968	34.63	26.81	7.82
1969	38.01	36.04	1.97
1970	43.22	39.95	3.27
1971	44.13	45.56	-1.43
1972	49.78	55.56	-5.78
1973	71.31	69.12	2.19

[a] Excluding Department of Defense shipments.

Source: U.S. Department of Commerce, 1976.

calculations by ICF, Inc. and Teknekron were different, and resolution of divergent results cannot be achieved by so simple a means as ascribing them to the single factor of constant versus variable contributions from nuclear sources.

Taking all of these uncertainties into account it should be stressed that the extent of increased consumption of oil and gas and additional imports of petroleum reflects more contingencies than do any other potential impacts discussed in this chapter.

7.5 Cost Effectiveness of Revised NSPS

Cost-effectiveness, or cost-benefit analysis, represents an extremely useful methodology for assessing the relative advantages and disadvantages of a set of alternatives, such as revisions in NSPS. By making explicit the prices associated with the anticipated benefits, cost-effectiveness aids the decision maker(s) in focusing on critical issues. More generally, cost-effectiveness seeks to quantify the effects of each alternative and present them on a basis for comparing gains of each with the costs.

7.5.1 Costs of SO_2 Reduction on a Ton-Per-Year Basis

An important partial measure of the cost-effectiveness of alternative NSPS revisions is provided by considering the price calculated for each scenario at which a unit amount (such as one ton per year) of SO_2 is removed. That is, typically two alternatives are estimated to prevent emission of different amounts of SO_2 at costs to the electric utility industry (and hence ultimately to the consumer) which when calculated on a common basis represent different monetary values. It is then instructive to examine the marginal costs of the more expensive alternative: i.e., whether the cost of removing each ton per year (TPY) which would otherwise be emitted is higher or lower than the cost of each TPY removed under the cheaper option.

A specific measure of these marginal costs has been provided for two coal types and for selected scenarios as shown in Table 7-41. All calculations reflect a single power plant of 500 MWe generating capacity. Thus the specific question addressed is "What are the marginal costs per TYP of decreased SO_2 emissions under different NSPS for each 500-MWe plant erected?" Inferences as to cost-effectiveness on this basis should be readily extensible to an individual plant of any size; although the cost of each TPY can be expected to vary according to the size of the plant, it may be reasonably expected that a difference in plant capacity will not affect which of two NSPS alternatives is more cost effective.

Estimates in Table 7-42 readily show that for a coal with 3.5 percent sulfur content the TPY cost (on an annualized basis) for 90 percent removal of SO_2 is achieved at a lower cost for each TPY than for the baseline situation (i.e., maintenance of the present level of 1.2 lb $SO_2/10^6$ Btu). What is even more striking, is that the additional 8,300 TPY captured under the 90 percent scenario are achieved at a cost only 75 percent of that required at which each TPY is removed in the baseline situation. On this basis, the extra

TABLE 7-42

FGD COST EFFECTIVENESS ON A UNIT BASIS

FULL SCRUBBING 500 MW PLANT

Coal Type	SO_2 Captured (TPY)	Annualized Cost ($ Million/Year)	$/Ton
3.5%	55,600 (1.2)[a]	$27.8	$500
	63,900 (90% Removal)	$30.9	$485
	8,300	3.1	$375
0.8%	15,400 (80% Removal)	$22.8	$1480
	17,300 (90% Removal)	$24.8	$1435
	1,900	2.0	$1050

[a] Baseline situation, assuming maintenance of present NSPS of 1.2 lb $SO_2/10^6$ Btu heat input.

Source: Personal Communication, EPA, February 1978.

cost of removing an additional 8,300 TPY through a 90 percent reduction level may appear to represent a bargain.

Similar results are indicated when the same kind of calculations are applied to 0.8 percent coal under the two scenarios of 90 and 80 percent SO_2 removal. Again it is seen that the greater quantity of SO_2 captured from a 500-MWe power plant under the 90 percent reduction standard is achieved at a lower cost in TPY. Also, the cost of preventing emission of an additional 1,900 TPY represents a marginal cost of $1050 per ton - about 70 percent of the cost at which each ton is captured under the 80 percent removal scenario.

This particular measure adds a highly important dimension to the economic impacts of revised NSPS for SO_2. It is noteworthy because it is based on two representative coal types and a plant-size which may be fairly typical for the future. However, neither it nor any of the other aspects discussed in this section, whether singly or in combination, can provide a fully comprehensive basis for a final decision as is discussed below.

7.5.2 Limitations of Cost-Effectiveness

There are inherent limitations in cost effectiveness; and final decisions among important alternatives (such as revised NSPS) must be supplemented by the expertise of the decisionmakers. Some of the limitations reflect the present state-of-the-art and will likely be remedied by further scientific investigation. Others are due to constraints on the resources of time and human effort that can be devoted to the required data gathering and interpretation. Other areas lie outside the range of objective analysis and reflect differences in interests within the population affected and variations in values.

Cost-effectiveness seeks to quantify the effects of each alternative as a basis for comparing gains of each with the costs. When the objectives of a set of alternatives are limited and can be precisely defined, and when few indirect or secondary impacts are expected, the problem is simplified. Many variables that govern the extent of both gains and losses can be successfully measured and numerical values assigned, as is shown in this report. Costs of components of the operations involved can be quantified, as can the prices of end-products, the physical effects such as tons of pollutants released into the atmosphere, and the resources required. Many secondary impacts, however, cannot be successfully measured because there is no adequate data base to support the development of reliable measures. It is not possible within the scope of the present study to measure, for example, impacts from variations in the amount of oil and gas imported or ramifications of changes in the quantities of scrubbers produced. There is no way to assign a realistic measure to the possible increases in agricultural production that may result from "clean air", or to cost savings to property owners from pollutant reduction or to human health improvements. It is not possible to assess the potential effects on migration of workers and their families resulting from changes in anticipated coal production under the revised NSPS.

A major difficulty in the use of cost-effectiveness is the absence of a common base for costs and gains. To the extent that advantages and disadvantages can be reduced to the same unit of measurement, such as dollar-value, trade-offs among alternatives are simplified. It becomes possible to determine the net gain or loss of each and to consider the marginal costs and benefits.

A final limitation on cost-effectiveness is due to the uncertainty of projections into the future. Best estimates are subject to error from unforeseen events or conditions. By making explicit the assumptions about the future on which the analysis is based, the cost-effectiveness methodology serves the decisionmaker(s) who can then allow for possible future changes.

APPENDIX A

SO_2 REMOVAL MECHANISMS AND EFFICIENCY

Material in this appendix was extracted from "Technical Document on Applying Tentative NSPS for Coal Fired Steam Generators to Fluidized Bed Combustion" a draft prepared for the U.S. DOE, November 1977.

SO_2 Removal Overview

When coal and calcined limestone or dolomite are burned in a fluidized bed, the sulfur released from the coal reacts with the limestone or dolomite. In the presence of excess air, the sulfur in the coal is oxidized to SO_2 and the reaction with the sorbent produces calcium sulfate. To replace the used sorbent (limestone or dolomite) new limestone or dolomite is usually added into the bed where in-situ calcination takes place by the following reactions to produce lime (CaO) or calcined dolomite CaO·MgO:

$$CaCO_3 \longrightarrow CaO + CO_2$$

$$Ca\,CO_3 \quad MgCO_3 \longrightarrow CaO \quad MgO + 2CO_2$$

The reaction of the lime with SO_2 appears to be a fairly simple reaction

$$CaO + SO_2 + 1/2\ O_2 \longrightarrow CaSO_4$$

lime + sulfur dioxide + excess air ⟶ Calcium Sulfate.

However, it has been shown that the reaction in the bed with coal combustion is very complex. Many factors affect the retention of sulfur by the lime.

The most important factors include: Ca/S ratio, type of sorbent, bed temperature, bed pressure, and residence time. The discussion on sulfur removal is based on data from bench scale and small pilot plant operations, and it is difficult to estimate the effect scale-up to a commercial size unit would have on these data. The results are further limited since most of the data were gathered on only two sorbents and there is little information on low sulfur coal.

Atmospheric Fluidized Bed Combustors

The sorbent ratio (moles Ca/moles S) required to achieve a 90 percent reduction of SO_2 emission from small pilot scale AFB combustors is shown in Figure A-1, ranges from 3 to 4. This range of Ca/S values has been found to be independent of the sulfur content for higher sulfur coals, but is dependent on the specific sorbent employed as shown in Figure A-2. Table A-1 shows the Ca/S mole ratio required for a range of sulfur retention levels for two specific coals.

TABLE A-1

ESTIMATED Ca/S MOLE RATIO TO ACHIEVE VARYING SULFUR RETENTION LEVELS

Sulfur Retention Level	Sewickley Coal ([illegible] Sulfur) Ca/S Ratio	Pittsburgh Coal ([illegible] Sulfur) Ca/S Ratio
95	—	[illegible]
90	[illegible]	[illegible]
85	[illegible]	[illegible]
80	[illegible]	[illegible]
75	[illegible]	[illegible]
70	[illegible]	[illegible]

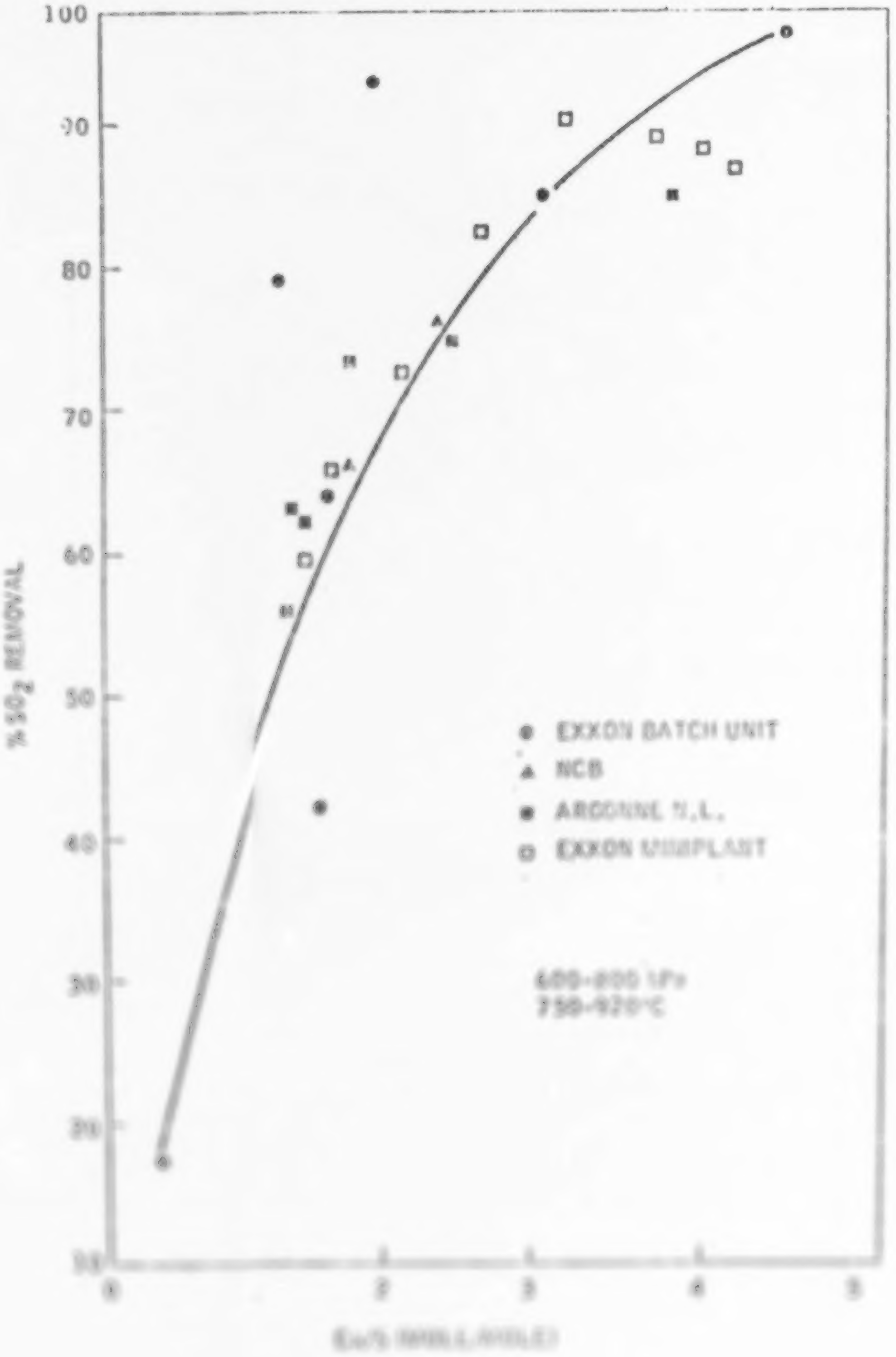
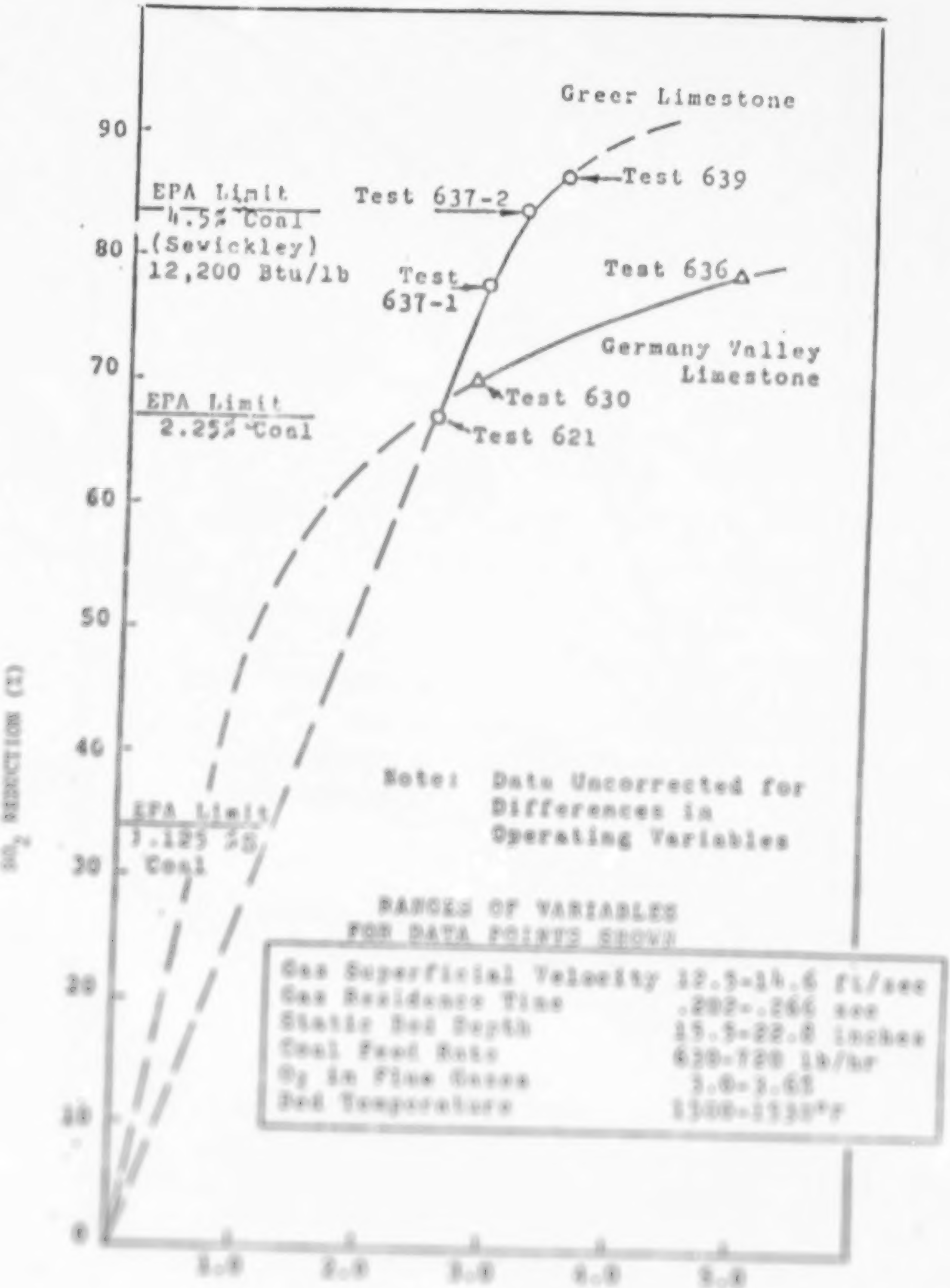


FIGURE [illegible]

EFFECT OF Ca/S MOLE RATIO ON SULFUR RETENTION



RANGES OF VARIABLES FOR DATA POINTS SHOWN

Gas Superficial Velocity	12.5-14.6 ft/sec
Gas Residence Time	.202-.266 sec
Static Bed Depth	15.5-22.0 inches
Coal Feed Rate	620-720 lb/hr
O_2 in Flue Gases	3.0-3.65
Bed Temperature	1500-1535°F

FIGURE [illegible]
COMPARISON OF PERFORMANCE OF GREER AND GERMANY VALLEY LIMESTONES

Figure A-3 indicates the variation in sulfur retention with change in bed temperature. The drop in sulfur retention at the lower temperatures is related to the failure of the sorbent to calcine. At higher temperatures, the decomposition reaction of $CaSO_4$ is favored, particularly if a minimum level of oxygen is not maintained (e.g., in carbon burnup cells, higher operating temperatures tend to expel SO_2 from the spent sorbent mixture if a minimum of 3.5 percent oxygen content is not maintained). As shown in Figure A-3 the sulfur retention has been observed to reach a maximum at about 1450°-1550°F. It should be noted that no satisfactory thermodynamic or kinetic explanation exists, at this time, for the occurrence of this maximum.

The effect of superficial gas velocity (gas residence time) on sulfur retention levels is shown in Figure A-4. The vertical scale indicates a reduction in the sulfur retention as the superficial velocity is increased, that is to say, as the residence time of the gases in the bed is reduced. In general, the sulfur retention increases as the bed depth is increased. This is expected since both the solids and the gas residence time are increased. There is, however, a practical limit on bed depth since the bed pressure drop increases directly as the bed depth increases, and the final bed depth may be dictated by the maximum allowable pressure drop for available fans.

Sorbent Requirements to Meet a 90 Percent SO Reduction Requirement and the Present NSPS Using an Atmospheric FBC System. Table A-2

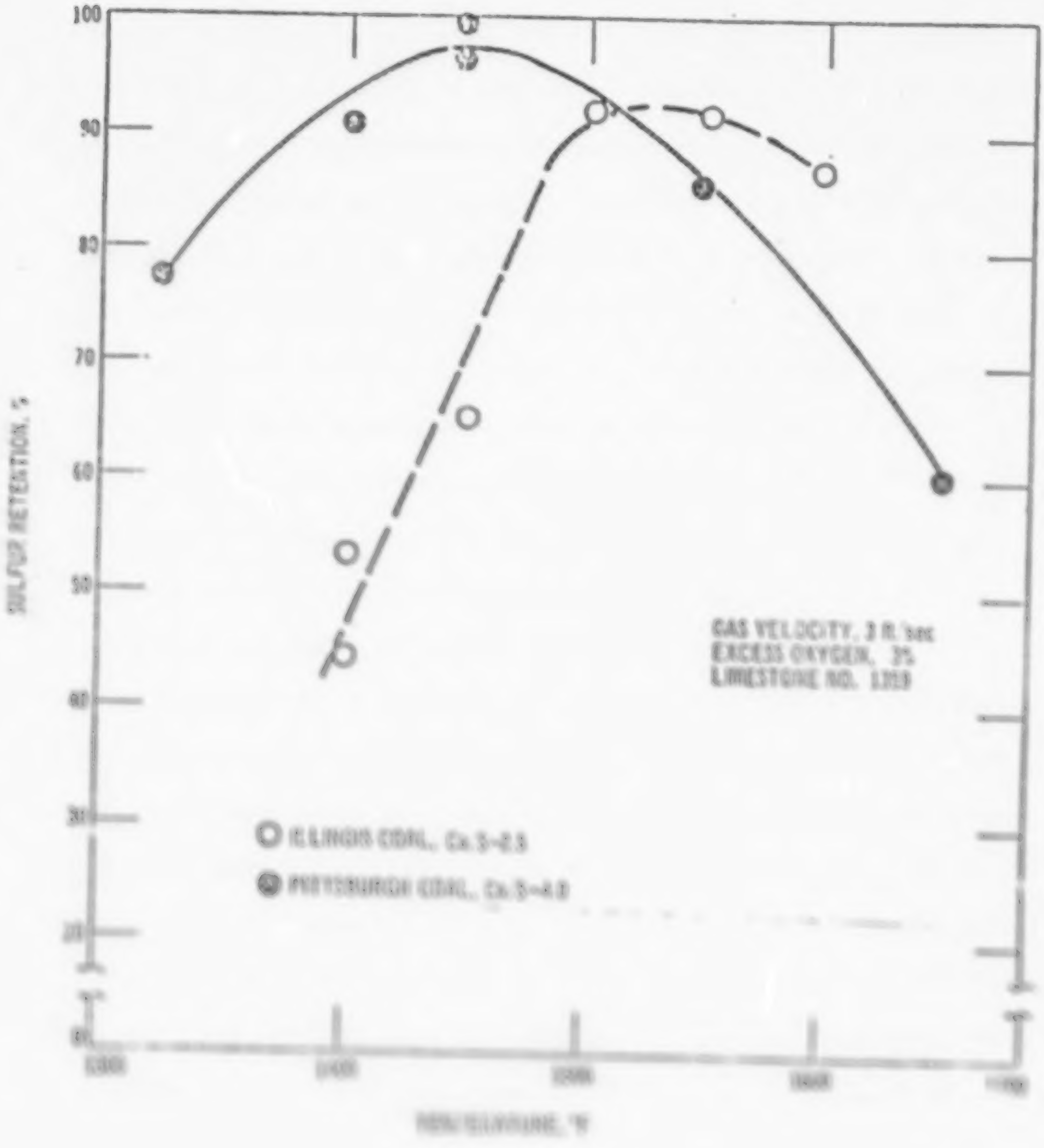


FIGURE A-[illegible]
COMPARISON OF SO_2 REMOVAL RESULTS – LIMESTONE SORBENT

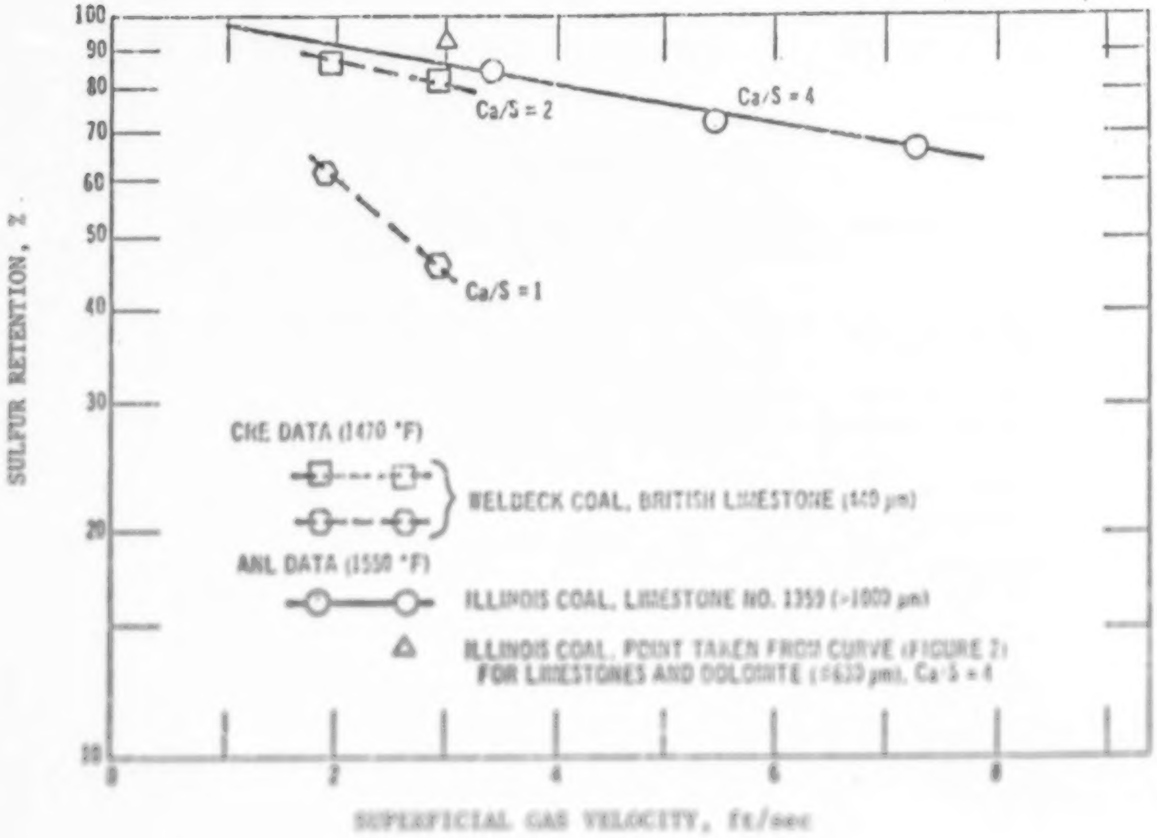


FIGURE A-6

SULFUR RETENTION AS A FUNCTION OF SUPERFICIAL GAS VELOCITY indicates the variation of limestone requirements (based on a Ca/S performance curve) for Greer limestone for different sulfur contents of the coal. The table compares the limestone quantities for 90 percent retention and for meeting the present 520 ng/J heat input (1.2 lb $SO_2/10^6$ Btu) standard for a fixed design atmospheric FBC system.

TABLE A-2

SORBENT REQUIREMENT FOR AFBC TO MEET EPA SO_2 EMISSION STANDARDS BASED ON PILOT PLANT DATA

Sulfur Content in Coal %	1	2	3	4	5
Limestone Required to Meet 90% SO_2 Reduction-lb/ton coal	219	437	656	875	1093
Limestone Required to Meet Present NSPS lb/ton coal	31	225	487	750	1030
Additional Limestone Required for 90% Control-lb/ton coal	188	212	168	125	62

Assumptions:

(1) Coal HHV of 12,000 Btu/lb.
(2) Limestone is 100% $CaCO_3$.

Pressurized Fluidized Bed Combustors:

Limestone and dolomite are inexpensive sorbents that are widely abundant in eastern U.S. areas where much of the high sulfur coal is found. It should be noted that the magnesium in dolomite does not absorb SO_2 under FBC conditions, and that to supply a given weight of calcium requires a dolomite input 1.8 times that of limestone and disposal of a correspondingly larger amount of solid waste. Differences in effectiveness of dolomite and limestone as sorbents, especially in PFBC, can partially compensate for the weight factor.

The activation of both limestone and dolomite for SO_2 absorption depends on the creation of a porous structure with a large internal surface area as a result of calcination reactions. Calcination of $CaCO_3$ occurs readily at bed temperatures in AFBC, but is inhibited at the higher pressures in PFBC, whereas calcination of $MgCO_3$ occurs readily in either AFBC or PFBC. Because of the inhibition of limestone calcination, dolomite is more effective than limestone at a given value of Ca/S (moles of calcium fed in the sorbent to moles of sulfur fed in the coal).

The effect of gas phase residence time, calculated as the ratio of the expanded bed height to the superficial gas velocity, was investigated at EXXON. The effect of residence time is more pronounced at high SO_2 retention levels and the magnitude is such that, for 90 percent SO_2 retention, decreasing the residence time from 3 to 0.5 seconds would require doubling the Ca/S ratio from 1.5 to about 3. The dependence on gas residence time of the Ca/S ratio required to meet the present EPA SO_2 emission standards is shown in Figure A-5. The effect is not large but evident. As for example, with a 2 percent sulfur coal, an increase in gas residence time from 1 to 3 seconds reduces the Ca/S requirement from 0.95 to 0.75.

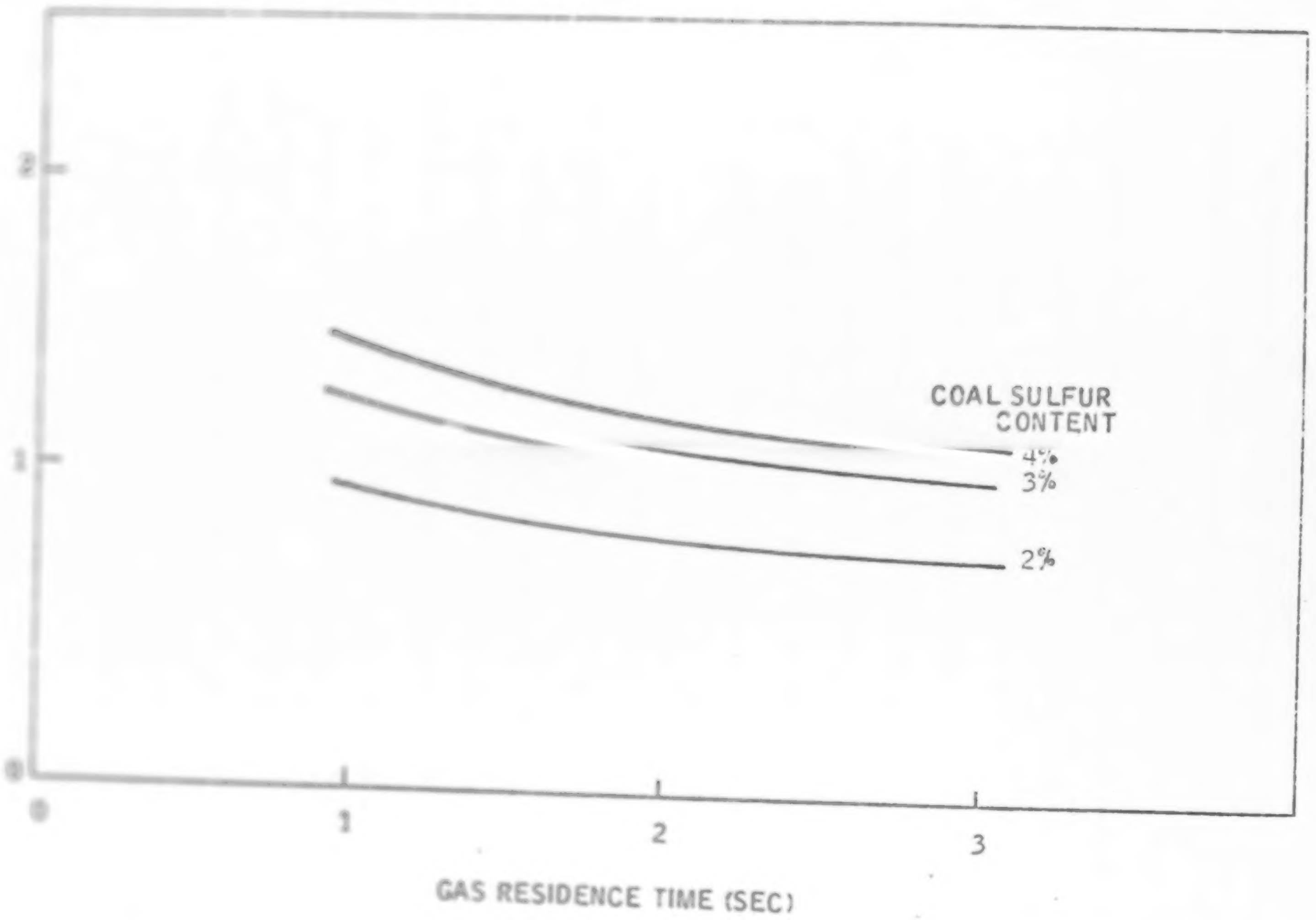


FIGURE A-5
EFFECT OF GAS RESIDENCE TIME ON Ca/S RATIO REQUIRED TO MEET PRESENT EPA SO_2 EMISSION STANDARD

At temperatures between 1400° and 1750°F, very little effect of temperature on sulfur retention for dolomite has been observed. SO_2 retention levels measured at 1270° to 1400°F were slightly lower than those measured at the higher temperature. However, with limestone a marked effect of temperature was observed, with increasing temperature giving higher SO_2 retention levels. These SO_2 retention levels were lower than those observed using dolomite sorbent, and it is felt that these effects were due to the inability of the limestone to calcine completely under pressurized combustion conditions. At higher temperature (1700° to 1740°F) limestone undergoes extensive calcination, and, although the limestone is not as active as dolomite, it is more active than at lower temperatures (1500° to 1650°F) where the stone is largely in the carbonate form.

Although an FBC utility boiler would normally be expected to operate in the temperature range of about 1550° to 1750°F, operation at temperatures down to about 1300°F would be required to turn-down the boiler output to match a decrease in the electrical power demand. A series of runs was made by EXXON using dolomite and limestone sorbent at temperatures near 1300°F to determine the behavior of the FBC system at these lower temperatures. Some runs were also made at temperatures as low as 1270°F to determine the lowest limit of operability. The minimum temperature at which combustion was stable was 1270°F. An attempt to decrease the temperature control in the combustor became erratic and carbon monoxide emissions in the flue gas increased sharply, denoting poor combustion.

Results of the tests are shown in Table A-3. A slight decrease in SO_2 retention was seen using dolomite sorbent at low temperatures. However, limestone was completely inactive and, therefore, cannot be used in a pressurized FBC unit unless some means of increasing its activity under low temperature "turndown" conditions can be found. Precalcination of the limestone is one possible way to do this and will be studied in the future.

Sorbent Feed Required to Meet the EPA SO_2 Emission Standards

A plot of sulfur retention vs. the sorbent mass feed rate (Figure A-6) shows that calcined Grove limestone (930°C/1700°F combustion temperature) is far more effective than the partly calcined stone (880°C/1600°F combustion temperature). It also shows that Pfizer dolomite is more effective on a weight basis than calcined limestone at sulfur retention levels greater than 70%. While far higher utilizations can be achieved with dolomite than with limestone, dolomite contains only 50 weight percent $CaCO_3$, as compared with a 100 percent $CaCO_3$ content for limestone. Figure A-6 can be used to estimate the sorbent feed rate required to meet the present EPA standard for any sulfur coal by calculating the equivalent retention level. Table A-4, which gives the sorbent feed requirements for 1 to 5 percent sulfur coals with 12,000 Btu/lb heating value, was prepared in this manner. At a coal sulfur level of 2 percent, 20 percent less limestone is needed as compared with dolomite to meet the present NSPS. At higher coal sulfur levels, it becomes increasingly

TABLE A-3

RESULTS OF RUNS AT TURNDOWN CONDITIONS

Operating Conditions:								
Avg. Bed Temperature, °C	891	762	762	690	684	750	674	938
Ca/S Molar Feed Ratio	0.61	0.94	1.1	1.5	1.4	2.5	2.5	3.5
Sorbent	PD	PD	PD	PD	PD	PD	PD	PD
Flue Gas Emission:								
SO_2, ppm	761	398	223	180	163	912	900	329
NO_x, ppm	135	125	149	114	102	120	174	125
CO, ppm	175	325	375	800	400	350	---	100
Sulfur Retention, %	40	48	71	76	82	0	6	70.3
Lb $SO_2/10^6$ Btu	2.29	1.42	0.78	0.64	0.5	2.69	2.64	0.80

PD = Pfizer Dolomite (No. 1337)

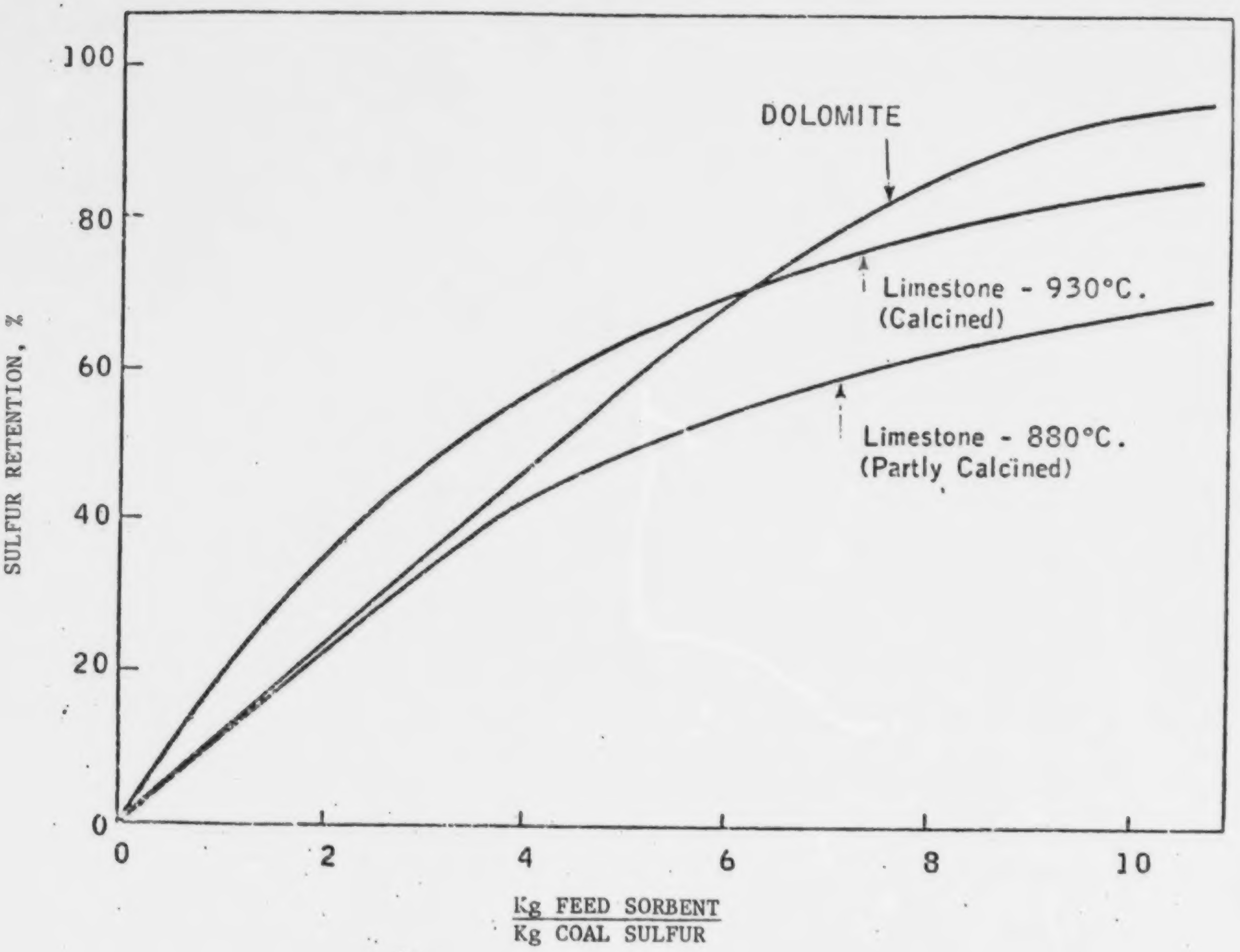


FIGURE A-6

COMPARISON OF DOLOMITE NO. 1337 AND LIMESTONE NO. 1359 AS SO_2 SORBENTS ON A MASS FEED RATE BASIS

TABLE A-4

SORBENT REQUIREMENTS FOR PFBC TO MEET EPA SO_2 EMISSION STANDARDS BASED ON PILOT PLANT DATA

Sulfur Content in Coal* %	1	2	3	4	5
Dolomite Required to Meet 90% SO_2 Reduction (lb/ton coal)	170	340	520	640	820
Dolomite Required to Meet Present NSPS (lb/ton coal)	23	200	400	580	800
Additional Sorbent Needed for 90% Reduction	147	140	120	60	20

*For coal with 12,000 Btu/ lb HHV

more attractive. Thirty percent more limestone than dolomite is required to meet the present NSPS with a 5 percent sulfur coal. With this coal, the Ca/S molar feed ratios would be 3.2 for limestone and 1.3 for dolomite. It should be noted that 90 percent of the U.S. coal reserves have a sulfur content under 5 percent. Also shown in Table A-4 are estimates of sorbent feed rates required to meet 90 percent reduction levels based on the assumption that the Ca/S ratio is independent of the coal sulfur content. At this level of sulfur retention, dolomite is the most effective sorbent for all sulfur levels.

APPENDIX B

ENERGY REQUIREMENTS

The information summarized in this appendix shows how energy requirements depend on SO_2 control method, level of control, and coal sulfur content. The data show that energy requirements for SO_2 control systems (expressed as energy required per unit of electrical generating capacity) depend only slightly on plant size.

Design Assumptions

The energy requirements for operating flue gas desulfurization systems were calculated based on the process designs summarized in Table B-1. The design assumptions for coal cleaning processes are shown in Table B-2. A unit train consisting of 100 coal cars and five locomotives was the design basis for coal transportation. Fuel consumption rates, transport distance, train speeds at full and reduced power, and coal dust blow-off losses were specified.

Table B-3 shows calculated energy requirements for the six processing operations in FGD systems. Particulate/chloride removal, reheaters, and fans account for 65 to 90 percent of total energy requirements for nonregenerable FGD processes. Sulfur recovery operations account for the majority of energy requirements for regenerable FGD processes.

Comparison of Energy Requirements by SO_2 Control Methods

Figure B-1 shows the energy required to meet the existing NSPS of 520 ng/J (1.2 lb $SO_2/10^6$ Btu) using different SO_2 control methods.

TABLE B-1

PROCESS DESIGN BASES FOR FGD PROCESSES*

Process Step	FGD Process				
	Limestone	Lime	MgO	Wellman-Lord/Allied	Double-Alkali
Particulate/Chloride Removal	Venturi	Venturi	Venturi	Venturi	Venturi
SO_2 Scrubbing	Mobile Bed	Mobile Bed	Venturi	Valve Tray	Mobile Bed
Reheat	Indirect Steam Reheater	Indirect Steam Reheater	Indirect Steam Reheater	Indirect Steam Reheater	Indirect Steam Reheater
Fans	Induced Draft Fans	Induced Draft Fans	Induced Draft Fans	Induced Draft Fans	Induced Draft Fans
Sulfur Disposal/Recovery	Lined Settling Pond	Lined Settling Pond	Production of Sulfuric Acid	Production of Elemental Sulfur	Lined Settling Pond

*Selection of processing techniques was based on data from the open literature which were representative of commercially available systems.

TABLE B-2

DESIGN ASSUMPTIONS FOR PHYSICAL COAL CLEANING FACILITY

- 40% sulfur removal
- 95% of energy recovery efficiency
- The electric power requirements for a 278 kg/s (500 ton/hr) cleaning plant are 2980 kW.
- The heat duty of a thermal dryer is 534 kJ/kg (230 Btu/lb) of coal dried.
- One half of the clean coal product (the coal fines) is thermally dried.
- Heat for the thermal dryers is supplied by burning a portion of the clean coal product.
- 50% of the ash content of the coal is removed.
- The average heating value of the clean coal is 29.2 MJ/kg (12,500 Btu/lb).

TABLE B-3

ENERGY REQUIREMENTS FOR THE PROCESSING OPERATIONS IN FGD SYSTEMS

	Energy Requirements for Flue Gas Desulfurization, MJ/s							
FGD Process	Coal Sulfur Content	Raw Material Handling and Preparation	Particulate/ Chloride Removal	SO_2 Scrubbing	Reheat	Fans	Sulfur Recovery/ Disposal	Total System Energy Requirements**
Limestone	3.5%	2.2	9.0*	8.8	18.3	10.4*	0.3	49.2
Lime	3.5%	0.2	9.0*	6.3	18.3	10.2*	0.3	44.3
Magnesia Slurry	3.5%	0.5	3.0	2.5	15.3	14.7	41.1	77.5
Wellman-Lord/Allied	3.5%	0.2	3.0	0.9	16.8	18.3	136	176
Double-Alkali	3.5%	0.3	3.0	2.4	18.2	14.9	0.7	39.8

* Energy required by fans to overcome pressure drop associated with particulate removal is included in the particulate removal operation.

** Utilities and Services for the FGD processes account for the discrepancies in system totals.

Assumptions:
500 MW power plant (net generating capacity)
90% SO_2 removal
Uncontrolled power plant net heat rate = 2640 J/kW-s
Steam produced in Magnesia Slurry and Wellman-Lord/Allied process is used within the process.
Wellman-Lord/Allied process produces sulfur as a by-product.

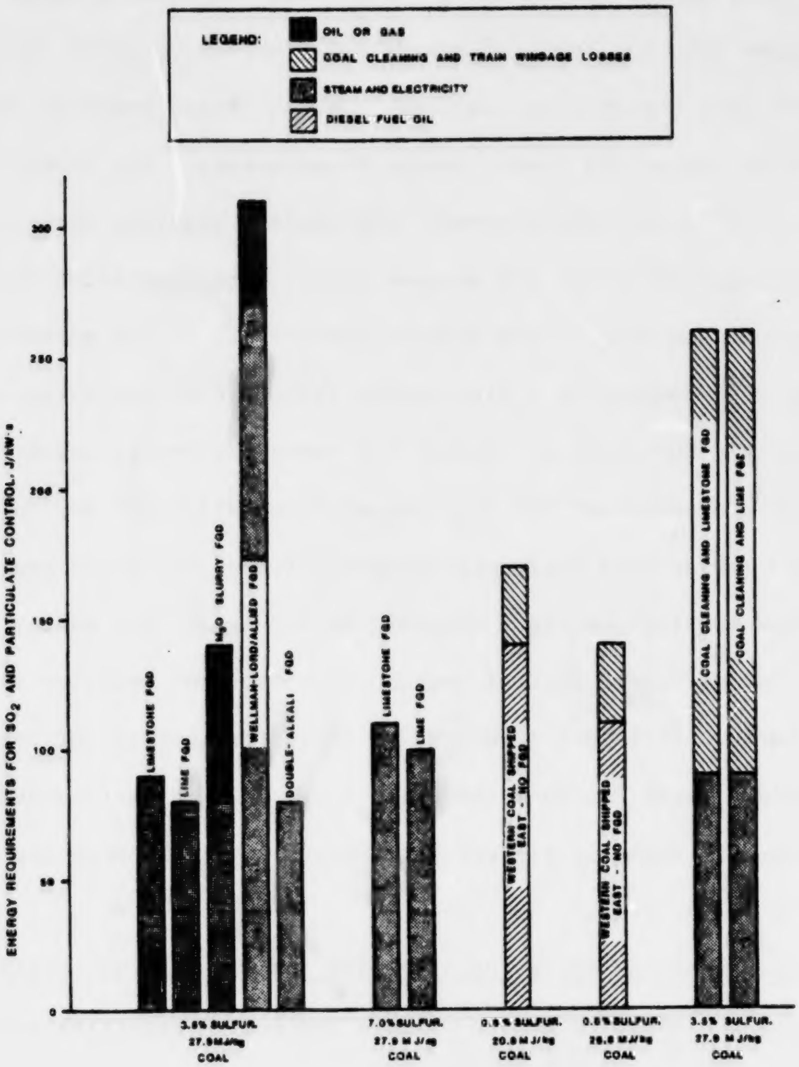


FIGURE B-1

ENERGY REQUIREMENTS FOR SO_2 CONTROL - 520 ng/J AT 500 MW PLANT

Total energy requirements for several coal compositions are separated into the types of energy required, i.e., steam fuel oil, natural gas, electricity, and coal losses. Nonregenerable FGD processes impose the lowest energy requirements. The combination of coal cleaning and nonregenerable FGD systems requires three times the energy required by the FGD process alone. Transportation of low sulfur western coal to the Midwest requires 25 to 100 percent more energy than combusting a high sulfur-eastern coal and using a nonregenerable FGD process. Figure B-2 shows the energy required to meet a standard of 90% SO_2 removal using different SO_2 control methods for several coal compositions. Figure B-3 shows energy requirements for meeting a standard of 220 ng/J. The energy requirements for different control methods have the same relative variations for the more stringent standards as those for meeting the existing standard. Table B-4 summarizes the total SO_2 and particulate energy requirements shown in Figures B-2 through B-4 for combusting a 3.5 percent sulfur coal.

Comparison of Energy Requirements for Alternative Levels of the SO_2 NSPS. Figure B-4 shows the energy penalties associated with two levels of SO_2 control: the existing standard, and the more stringent standard calling for 90 percent SO_2 removal. As shown in Figure B-4, for most control methods the energy penalty for achieving 90 percent removal is about 10 percent higher than that required to meet the existing NSPS.

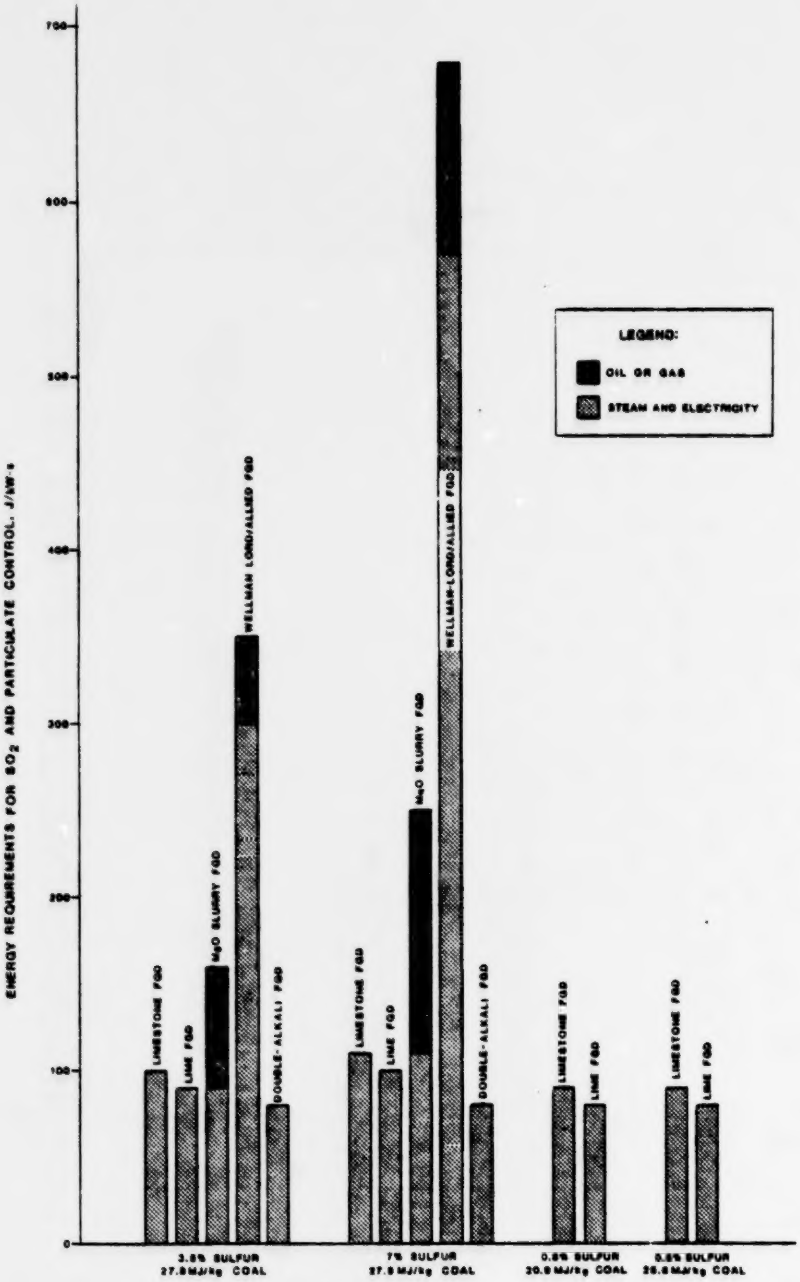


FIGURE B-2

ENERGY PENALTIES FOR SO_2 AND PARTICULATE CONTROL - 90% SO_2 REMOVAL CONTROL LEVEL, 500 MW PLANT

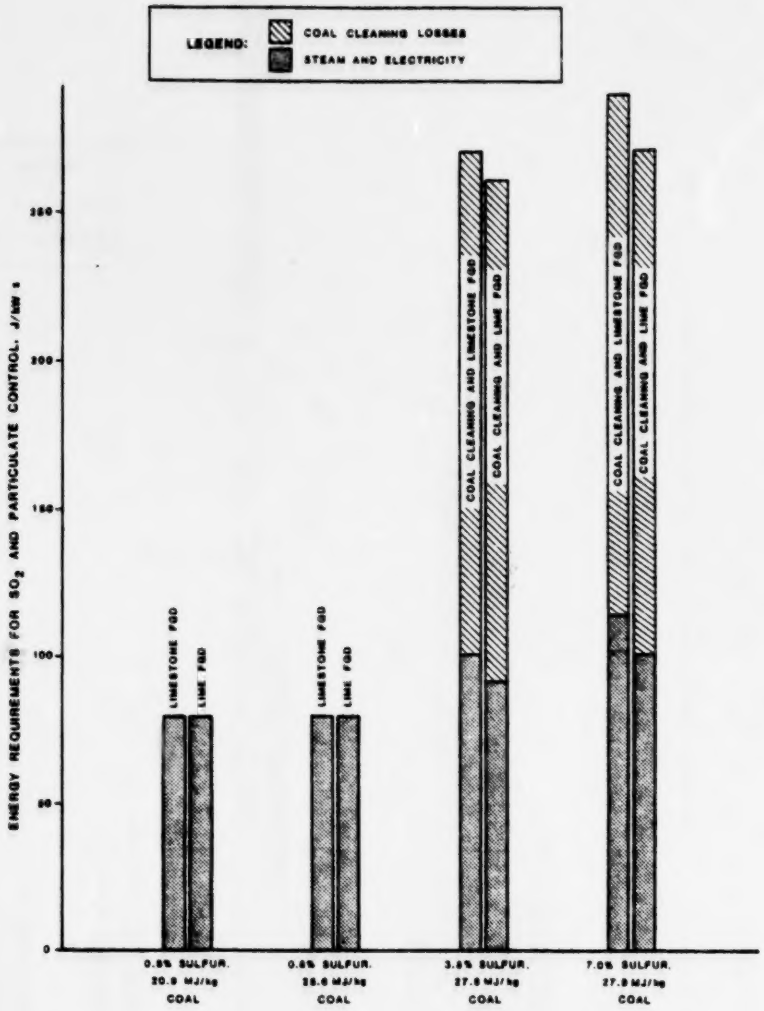


FIGURE B-3

ENERGY REQUIREMENTS FOR SO_2 AND PARTICULATE CONTROL - 220 ng/J CONTROL LEVEL 500 MW PLANT

TABLE B-4

TOTAL SO_2 AND PARTICULATE ENERGY PENALTY ASSOCIATED WITH DIFFERENT METHODS OF CONTROLLING SO_2 EMISSIONS - 500 MW PLANT, 3.5% SULFUR COAL

SO_2 Control Process	Energy Penalty (% Energy Input to Equivalent Uncontrolled Power Plant)		
	NSPS	90%	0.5 lb SO_2/ MM Btu
Nonregenerable FGD			
Limestone	3.4	3.8	NE
Lime	3.0	3.4	NE
Double-Alkali	3.0	3.0	NE
Regenerable FGD			
Magnesia Slurry	5.3	6.1	NE
Wellman-Lord/Allied	11.7	13.2	NE
Coal Cleaning Plus Lime/Limestone FGD	9.8	NE	9.8/10.2

NE = Not Examined

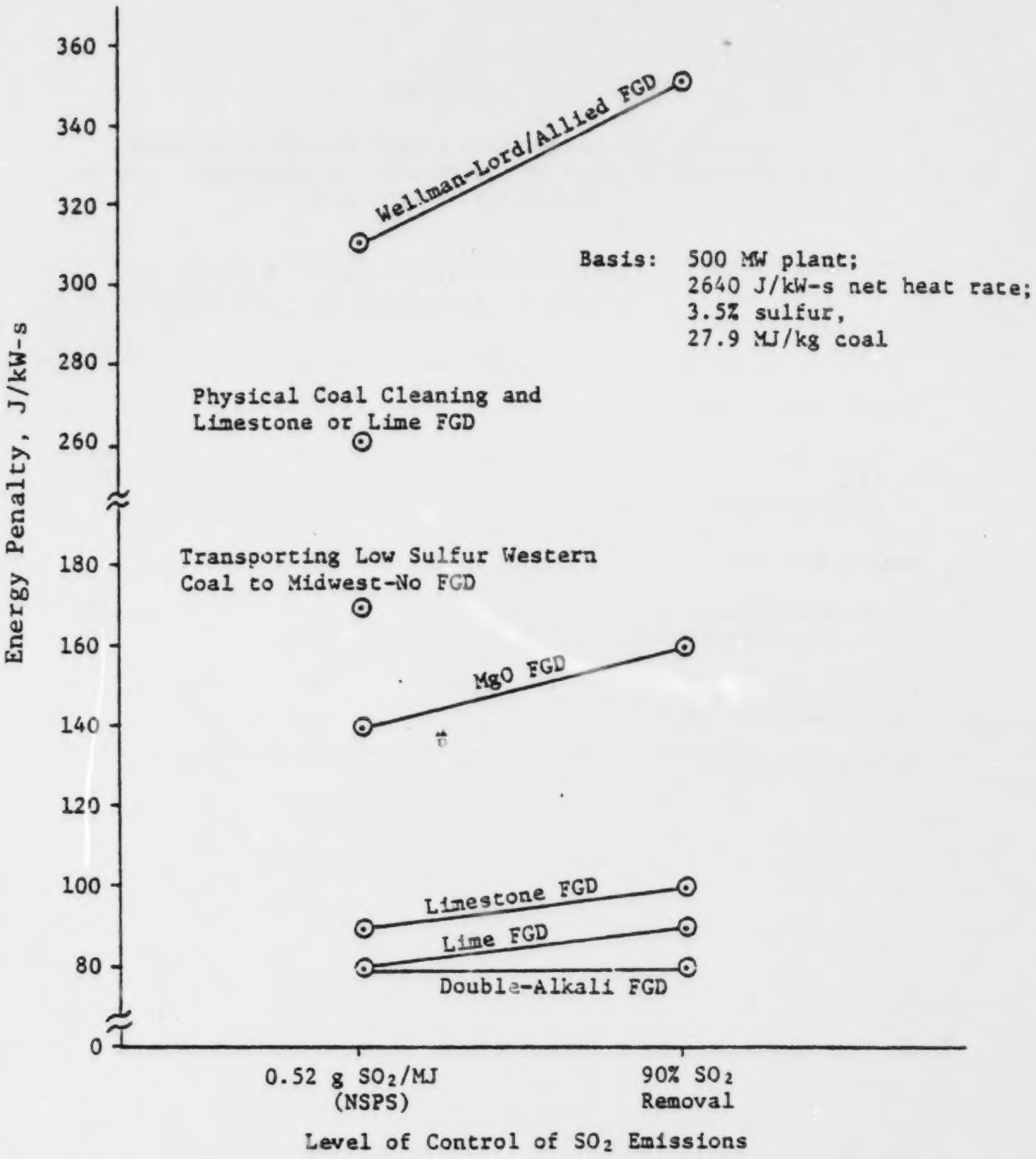


FIGURE B-4

ENERGY PENALTIES FOR SO_2 CONTROL - SUMMARY OF EFFECTS OF SO_2 CONTROL LEVEL

The results of the study also show that for combustion of low sulfur western coal, 90 percent SO_2 removal requires up to 10 percent more energy than controlling emissions to 220 ng/J (0.5 lb $SO_2/10^6$ Btu) of heat input.

When flue gas reheat and particulate/chloride removal are excluded from the limestone and lime systems, the energy requirement of these systems is reduced by 50 to 60 percent. For the double-alkali, magnesia slurry and Wellman-Lord/Allied processes, the particulate/chloride removal operation is required to prevent buildup of chlorides in the SO_2 scrubbing liquor and to prevent contamination of the chemical process by particulates. However, excluding flue gas reheat requirements would reduce the energy required for operation of the MgO system by 15 to 25 percent, the Wellman-Lord/Allied system by about 10 percent, and the double-alkali system by about 50 percent.

APPENDIX C

REHEAT OF SCRUBBED FLUE GASES

A substantial amount of FGD energy is expended in the reheat of flue gases. This appendix discusses the need for reheat systems, and the problems and solutions associated with their usage. Material in this appendix was extracted from "Flue Gas Desulfurization Systems: Design and Operating Parameters, SO_2 Removal Capabilities, Coal Properties and Reheat" a draft prepared for the U.S. EPA, November, 1977.

Purpose and Need for Reheat

Flue gases are normally discharged to the stack at ~120° to 150°C (250° to 300°F). The temperature is selected to remain above the dew point in order to reduce corrosion and permit carbon steel to be used for fans, ducting, and stack lining.

When a wet scrubber is inserted between the air heater and stack for SO_2 removal, the flue gas exiting the scrubber is saturated with water and cooled to the saturation temperature of about 50°C (125°F). Discharge of the cool, wet gas to the stack can lead to:

- Condensation of water vapor and sulfur oxides, resulting in the acidic water corrosion of downstream ducts, fans, and stack lining
- Impaired plume rise and, hence, poorer dispersion of residual pollutants for a given stack height
- Deposition of scrubber residue on downstream fan blades, resulting in imbalance
- A visible plume as water vapor condenses

- Stack rain, or mist droplets, that can settle around the power station.

To prevent corrosion of downstream components, the treated gas may be reheated to a higher temperature before discharge.

Methods of Reheat

Flue gas can be reheated in many ways, and several approaches have been developed. The basic differences in reheat methods are the energy sources used and the methods of transferring that energy to the flue gas. Reheat methods currently in use include:

- Direct inline reheat - using steam or hot water heat exchangers
- Direct combustion reheat - using gas or oil in either inline burners or external combustion chambers
- Indirect hot air reheat - using steam to heat air which is then mixed with the scrubbed gas
- Bypass reheat - bypassing a portion of the untreated hot flue gas to mix with the scrubbed gas.

In the U.S., the scrubbed gas is generally reheated by 15° to 40°C (30° to 100°F). Except for bypass, the energy penalty for reheat may range from 1 to 5 percent of the heat input to the boiler system.

Direct Inline Reheat. Inline steam reheat is the most prevalent method in the United States, although a few systems use hot water. An inline reheater consists of a heat exchanger installed in the flue gas duct, and is generally simple in design and installation. For a given degree of reheat, the energy consumption is lower than for other types of reheat, except bypass. The major problems encountered have been plugging, corrosion, and vibration of the heat exchanger tube bundles.

Plugging occurs from entrainment. Once the scrubber liquor deposits on the reheater, the dissolved and suspended solids bake onto it. This deposit continues to grow, blocking the gas flow, increasing the pressure drop, and helping to induce corrosion from the localized high temperature and concentrated salts. The effectiveness of the heat transfer surface is progressively reduced as the deposit builds up. To minimize problems, an efficient scrubber mist eliminator is essential. Most direct inline reheaters incorporate a steam or air soot blower for maintaining clean reheat surfaces. Corrosion and pitting have been attributed to periodic acid conditions and to chlorides. Effective design of the mist eliminator will minimize this. Operating experience suggests that certain materials should not be used, such as carbon steel, 304SS, 316SS, and Corten. Structural design against vibration is essential.

Direct Combustion Reheat. The major advantage of this type of reheat is operational reliability, especially if gas is used, because there is no heat transfer surface on which fouling can occur. The main drawback in the United States is the limited availability and cost of the oil or gas required. Where oil is used, problems have occurred in attempting to maintain the flame within the main flue gas stream. This saves space, but typically does not work well. An external combustion chamber of adequate size is essential. Refractory failures have occurred in the combustion chamber from flame impingement, attack from condensation during downtime, vibration, and too rapid heating. Careful specification of refractory and subcomponents is essential and provision must be made for the combustion chamber to be heated up slowly.

Indirect Hot Air Reheat. Indirect hot air reheaters have had fewer problems than inline types. One advantage of this type of reheat is that it provides desirable dilution for moisture content and residual pollutant concentration in the stack gas. Disadvantages are higher capital investment, higher steam consumption for the same degree of reheat, and increased stack gas volume. The temperature of the hot air before mixing is higher than 200°C (400°F) and can destroy the usual coatings used to protect ducts and scrubber walls. Hot air must be prevented from entering the system without cold gas flow during startup and shutdown. For the same degree of reheat, indirect hot air reheat has the highest energy requirement. However, for the same amount of energy consumption, it may have equal or better benefits than other types of reheat.

Bypass Reheat. Bypass reheat has the advantages of low capital investment, negligible operating cost, and simple, reliable operation. However, the maximum degree of reheat obtainable is limited by the overall SO_2 removal requirement versus the SO_2 removal capability of the FGD system. Separate fly ash removal is required to ensure that the bypassed flue gas is sufficiently low in dust content to meet particulate emission standards. Operating experience with bypass reheat in the United States is limited to only one installation, but additional FGD systems are under construction with provision for bypass reheat.

Alternatives to Reheat

A number of alternatives to reheating are available. Whether or not they are feasible must be considered on a case by case basis. To the extent that excessive ground concentration of residual pollutants is a problem due to reduced plume buoyancy, one alternative to reheating is to build a taller stack. Because there is no energy penalty, the taller stack could be more economical than reheating even though it involves a high capital cost. However, this option is specifically limited by the Clean Air Act Amendments of 1977.

To limit corrosion, one may either select materials that are inherently resistant to corrosion or use coatings to cover materials subject to corrosion. If the purpose of reheat is to protect a downstream fan, an alternative is to place the fan upstream of the scrubber, although this requires a precipitator to remove erosive particulate matter. Wet, or washed, fans have also been used.

Using reheat to overcome the effect of liquid entrainment from the scrubber is costly and not necessarily the best answer to such problems. The use of more efficient mist eliminators would be the preferred alternative. One form of liquid emission that would not be affected by better mist elimination results from liquid condensate forming inside the stack. Such an effect can be reduced or eliminated by the combination of insulation on the stack so as to reduce condensation likelihood, plus the use of a lower velocity stack.

There is very little, other than reheat, that is effective in eliminating a visible vapor plume. However, plume appearance and, in particular, the length of a visible plume are strong functions of atmospheric conditions. When the gas leaves the stack, water vapor condenses in the cooler atmosphere forming a visible plume. As the plume disperses, condensed vapor evaporates at a rate depending on the ambient humidity and temperature. With high external humidities early in the day, the visible plume may travel long distances before disappearing. In a desert environment at mid-day, on the other hand, the visible plume vanishes rapidly. If the purpose of reheat is a cosmetic one, one approach could be to use variable reheat. That is, reheat could be limited to those periods of atmospheric conditions during which a plume of objectionable length would otherwise occur.

Reheating should not be considered as a necessity, but as one of a number of approaches for consideration in optimizing sulfur dioxide absorption systems. Because of the high cost of reheat installation and operation, some FGD system operators have selected "no reheat," or "wet-stack," design.

APPENDIX D

FGD SYSTEM PERFORMANCE

Flue gas desulfurization processes are categorized as regenerable or nonregenerable depending on whether sulfur compounds are separated from the absorbent as a by-product or disposed of as a waste. Nonregenerable processes produce a sludge that requires disposal in an environmentally sound manner. Regenerable processes have additional steps to produce by-products such as liquid SO_2, sulfuric acid, or elemental sulfur. The nonregenerable group includes lime and limestone, sodium carbonate and double alkali scrubbing techniques. The regenerable systems currently in operation are typified by the magnesium oxide and the Wellman-Lord systems. The following sections briefly describe these processes, their efficiency and reliability, and present information on their performance at selected installations.

Lime and Limestone Scrubbing

Lime slurry scrubbing is a wet scrubbing process that uses a lime slurry to react with SO_2 in the flue gas. Lime is fed into the system and combined with water to form a slurry, which is then contacted with the flue gas to absorb SO_2. Sulfur dioxide reacts with the slurry to form calcium sulfite and sulfate, which are removed from the system as sludge. The limestone slurry scrubbing process is similar, although it uses limestone rather than lime as the reagent. Facilities using lime and limestone systems have reported both long and short term SO_2 removal efficiencies in excess of 90 percent in the United States. Both have successfully operated on high- and low-sulfur coal-fired applications.

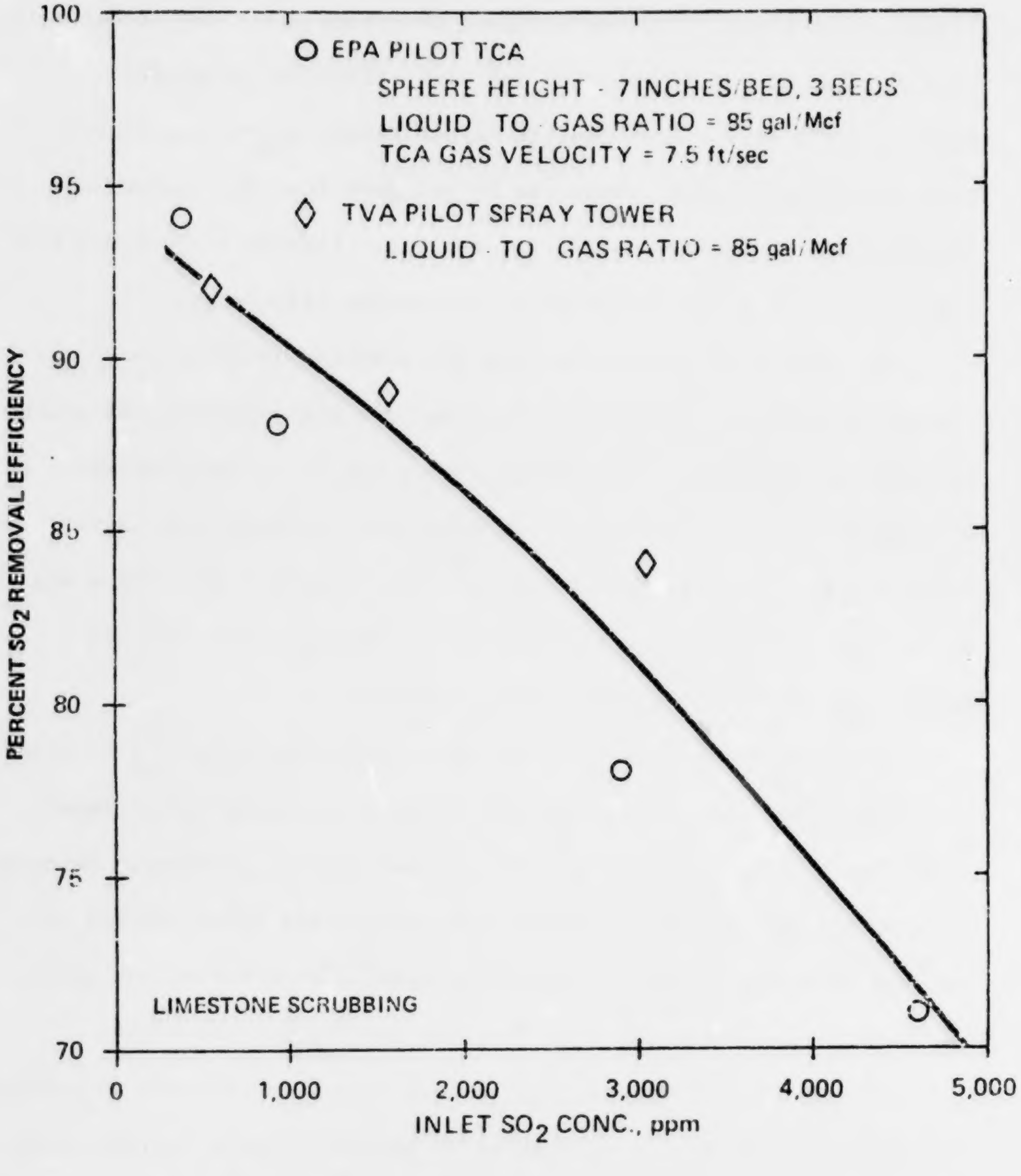
Many operating lime and limestone systems were designed for SO_2 collection efficiencies of less than 90 percent, since this was all that was required to meet an applicable regulation. Often an efficiency in the range of 60 to 70 percent was sufficient, and such values were used to establish system design.

Design of newer systems which are required to achieve high efficiency must take into account a number of key design variables including:

- inlet SO_2 concentration
- liquid to gas ratio
- scrubber gas velocity
- scrubber liquor inlet pH
- type of absorber

Higher removal efficiencies can be more easily achieved at lower SO_2 inlet concentrations because the amount of SO_2 that must be absorbed per unit of scrubbing liquor to achieve a specified outlet concentration is smaller. At low SO_2 concentrations the alkali in the liquor can react with a greater percentage of the SO_2 and affect a greater removal efficiency under a given set of operating conditions. Figure D-1 shows removal efficiency vs SO_2 inlet concentration for a given set of conditions.

Higher efficiencies are realized at higher liquid to gas (L/G) ratios for lime and limestone systems. For a given absorber, increased



Source: Bechtel, 1977.

FIGURE D-1

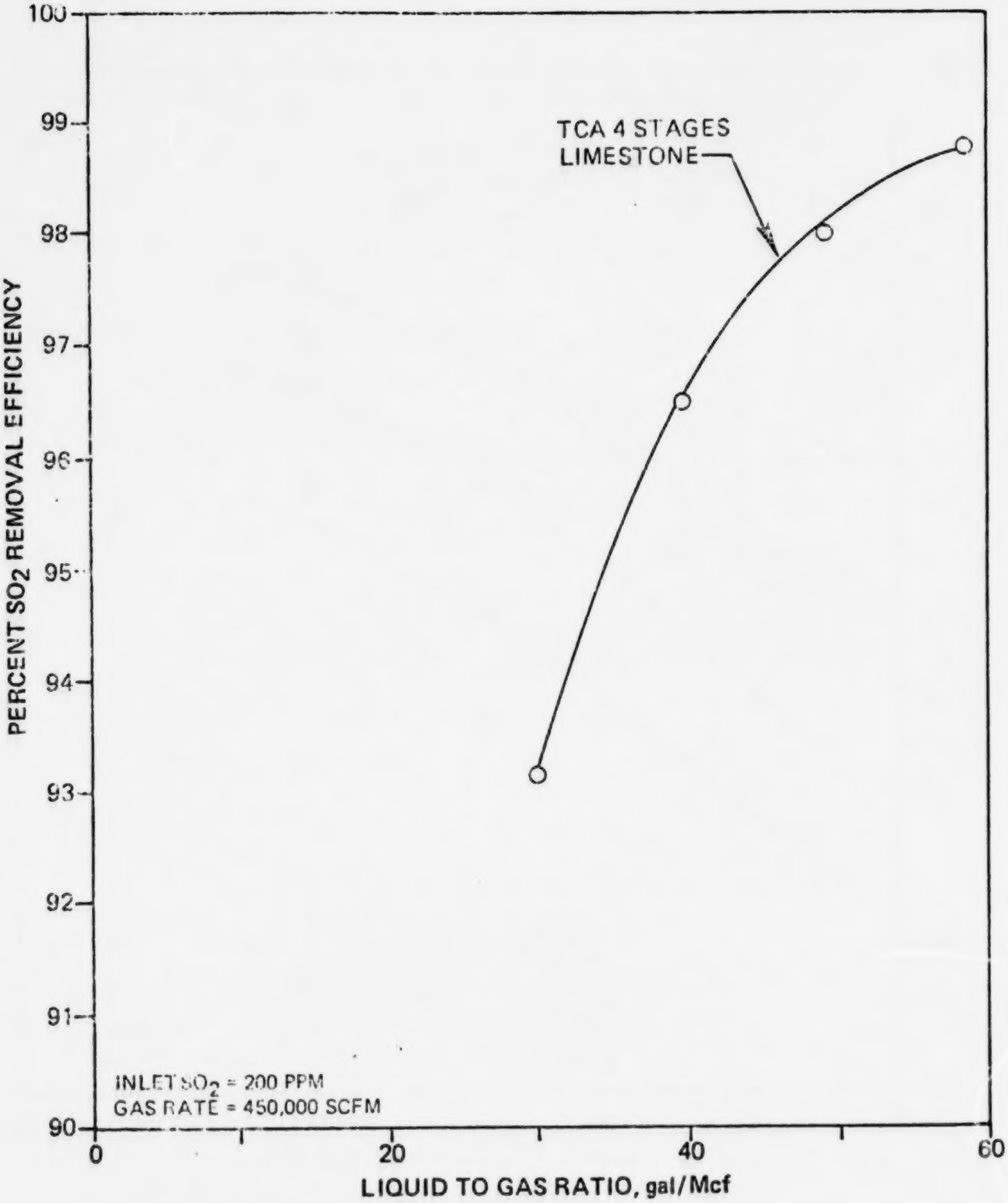
EFFECT OF INLET SO_2 CONCENTRATION ON SO_2 REMOVAL EFFICIENCY FOR FIXED DESIGN AND OPERATING CONDITIONS

L/G ratios will yield higher efficiencies until flooding and poor gas distribution occur. For new designs, absorbers which can accommodate high L/G ratios can be selected and high efficiency maintained. Higher liquid ratios also require larger pumps, pipes, and slurry reaction tanks. Again, these can be designed into the system and should cause no unusual operating problems. Figures D-2 and D-3 give some typical data on L/G ratios vs collection efficiency.

The effects of change in flue gas absorber velocity on SO_2 removal efficiency, when other variables are kept constant, vary with the type of absorber. For a spray tower, the efficiency decreases at a fixed L/G ratio. This effect is much less noticeable on packed and turbulent contact type absorbers (TCA) (Figure D-4). For a new plant, the scrubber would be designed for the required L/G when considered along with other design parameters.

Increased efficiency is achieved at higher pH (Figure D-5) since more alkali is available and higher dissolution rates are achieved. Operation at very high pH, however, causes scaling problems. Maintenance of the desired pH by careful measurement and close control of reagent feed and mixing system will prevent the pH variations which reduce efficiency (if too low) or cause scaling (if too high).

A large variety of absorber designs have been utilized to achieve SO_2 removal efficiencies as high as 99 percent. These include cross-flow horizontal spray chambers (Weir), spray towers, packed-grid towers, and turbulent contact (mobile bed) absorbers. The venturi



Source: Bechtel, 1977.

FIGURE D-2

EFFECT OF LIQUID-TO-GAS RATIO ON SO_2 REMOVAL EFFICIENCY WITH LOW SULFUR COAL AT THE MOHAVE POWER STATION

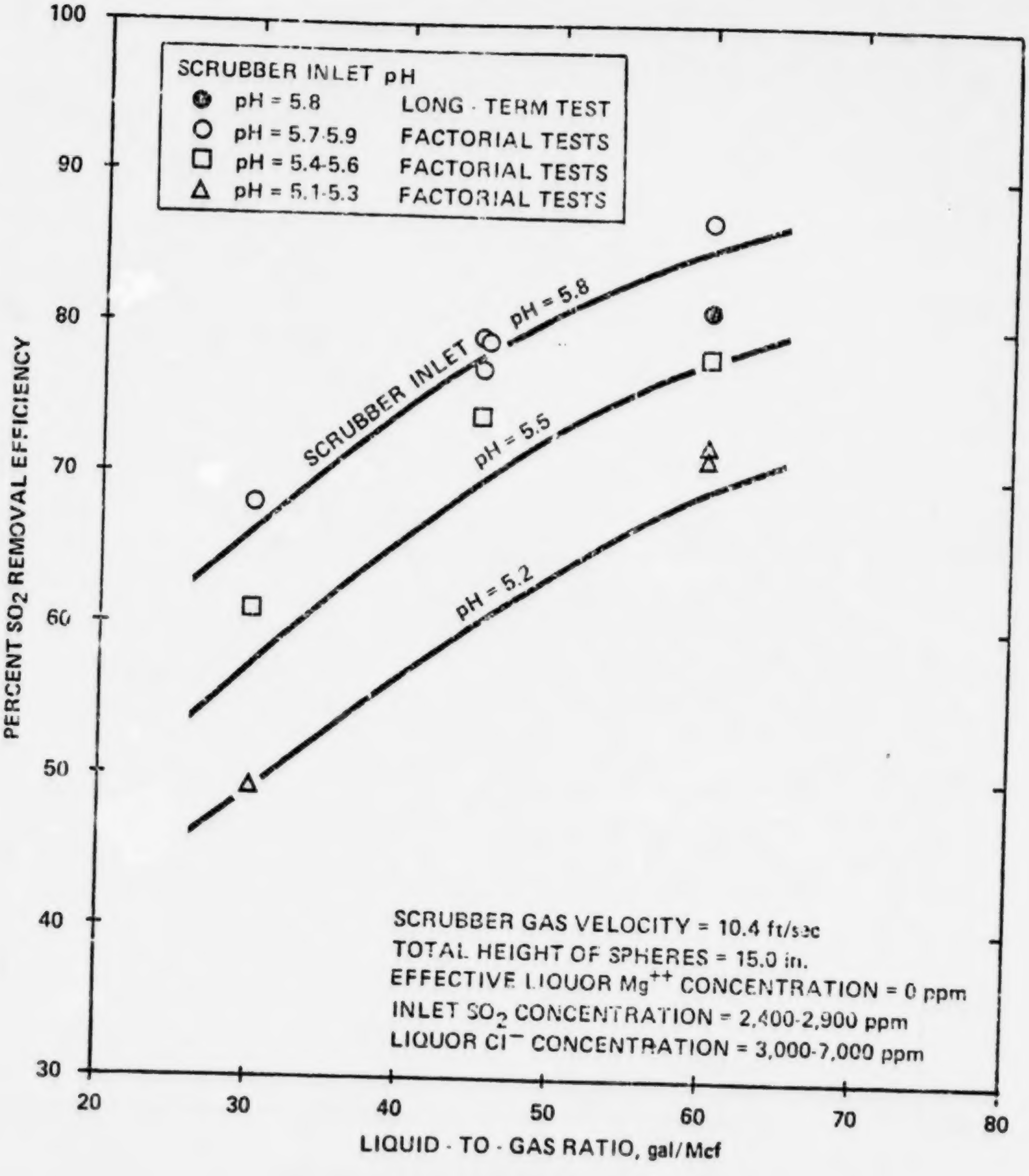


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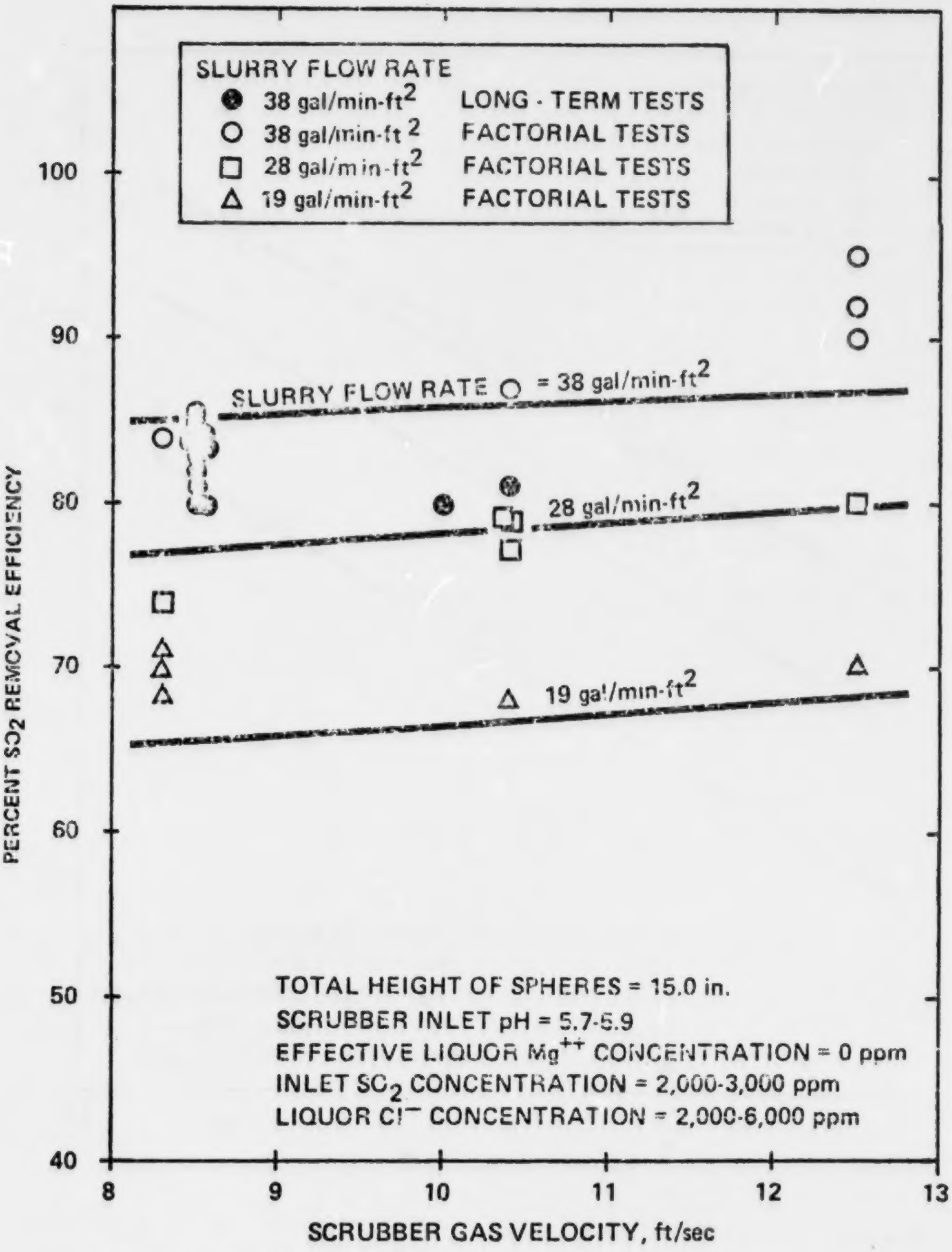
FIGURE D-3

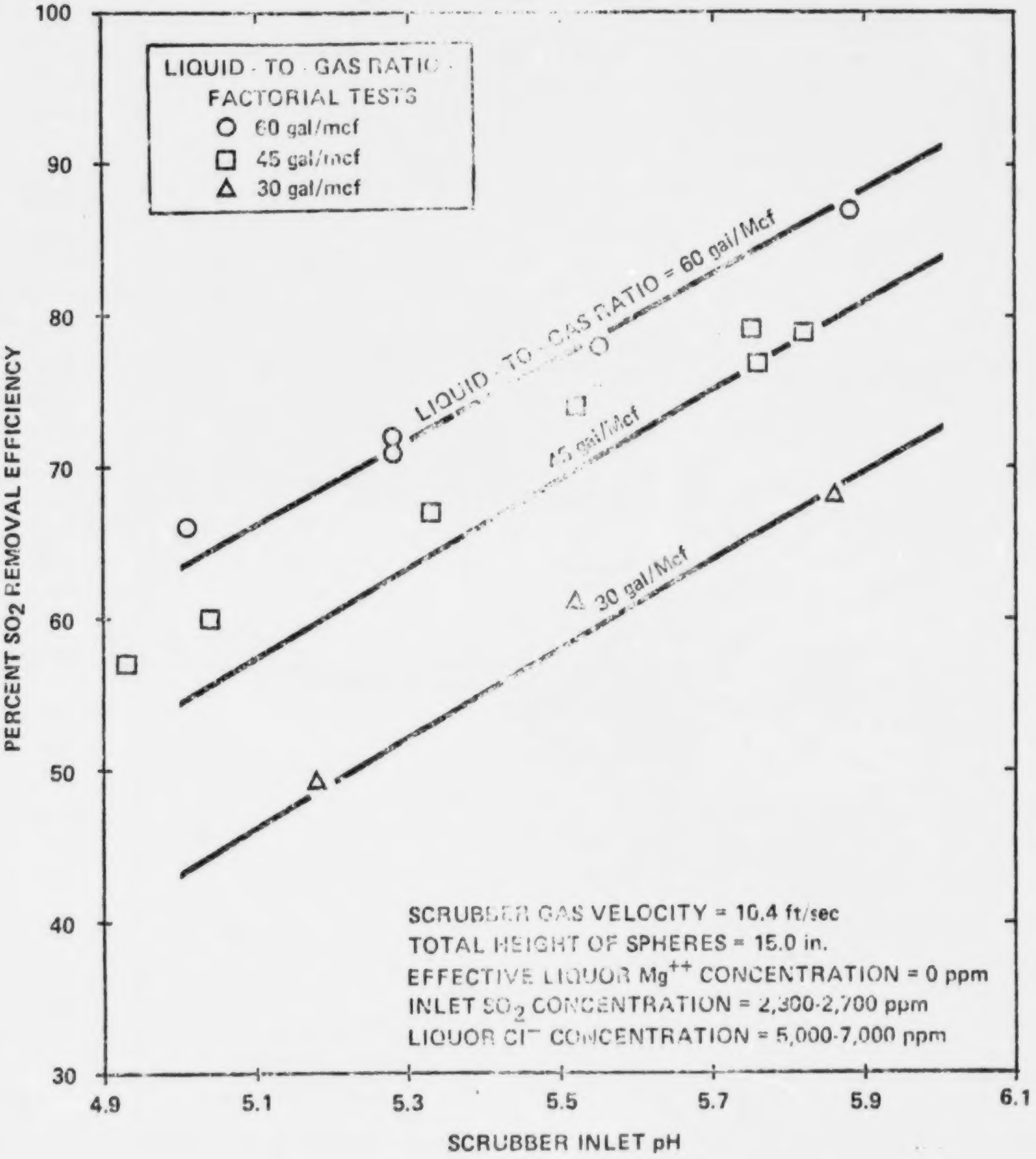
EFFECT OF LIQUID-TO-GAS RATIO ON SO_2 REMOVAL EFFICIENCY - TCA WITH LIMESTONE



Source: Bechtel, 1977.

FIGURE D-4

EFFECT OF GAS VELOCITY ON SO_2 REMOVAL EFFICIENCY- TCA WITH LIMESTONE



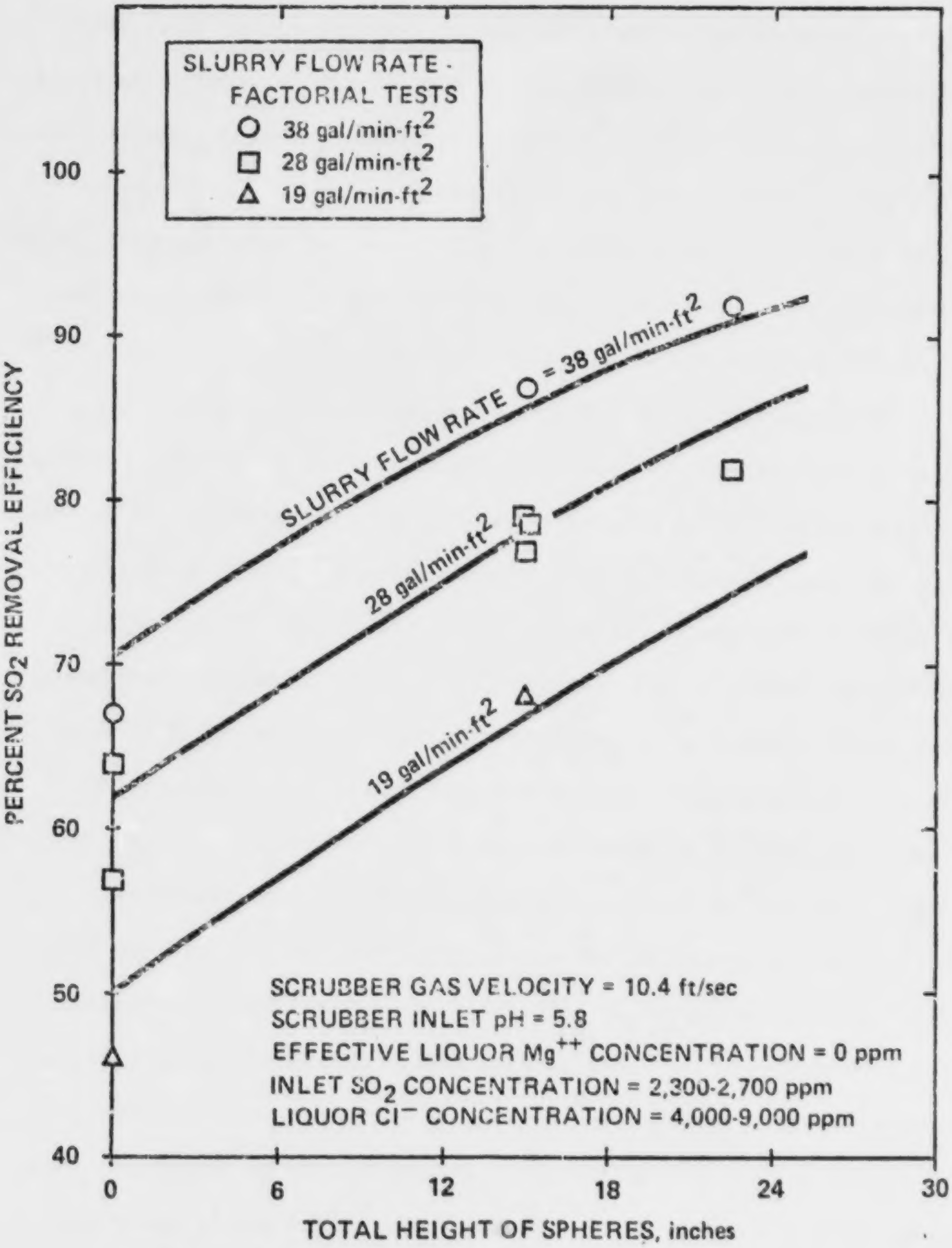
Source: Bechtel, 1977.

FIGURE D-5

EFFECT OF SCRUBBER INLET PH ON SO_2 REMOVAL EFFICIENCY - TCA WITH LIMESTONE type has also been used, however, it is more useful as a particulate removal scrubber an not as efficient for SO_2 absorption ducts short residence times (unless and additive such as MgO is used). The final selection and design of an absorber are usually based on previous test data and on the required liquid and gas flow rates. Spray towers (either horizontal or vertical) offer a number of advantages including simple internal design which decreases scaling potential, acceptance of high liquid flows and decreased maintenance.

Variations in the alternative absorbers can also affect SO_2 removal efficiency. For instance, Figure D-6 shows the effect of mobile packing height on SO_2 removal efficiency in a three-bed TCA. Increasing bed heights by adding more spheres increases slurry holdup in the scrubber. This has the combined beneficial effects of providing additional liquor holdup time for alkali dissolution and a greater gas-liquid contact area for improved efficiency. In the TCA, where sphere retaining grids are about 4 feet apart, the static sphere height per bed can be adjusted over a range of several inches. If greater removal is desired, the number of beds can be increased. Increasing the bed height, however, increases the gas pressure drop.

Other improvements in efficiency are achievable by increasing the packing height in fixed packing towers and by adding more trays in tray towers, although these types of scrubbers are not often used in slurry service because of their susceptibility to plugging. These improvements are made at the expense of increased gas pressure drop across the scrubber and, therefore, increased fan power requirements.



Source: Bechtel, 1977.

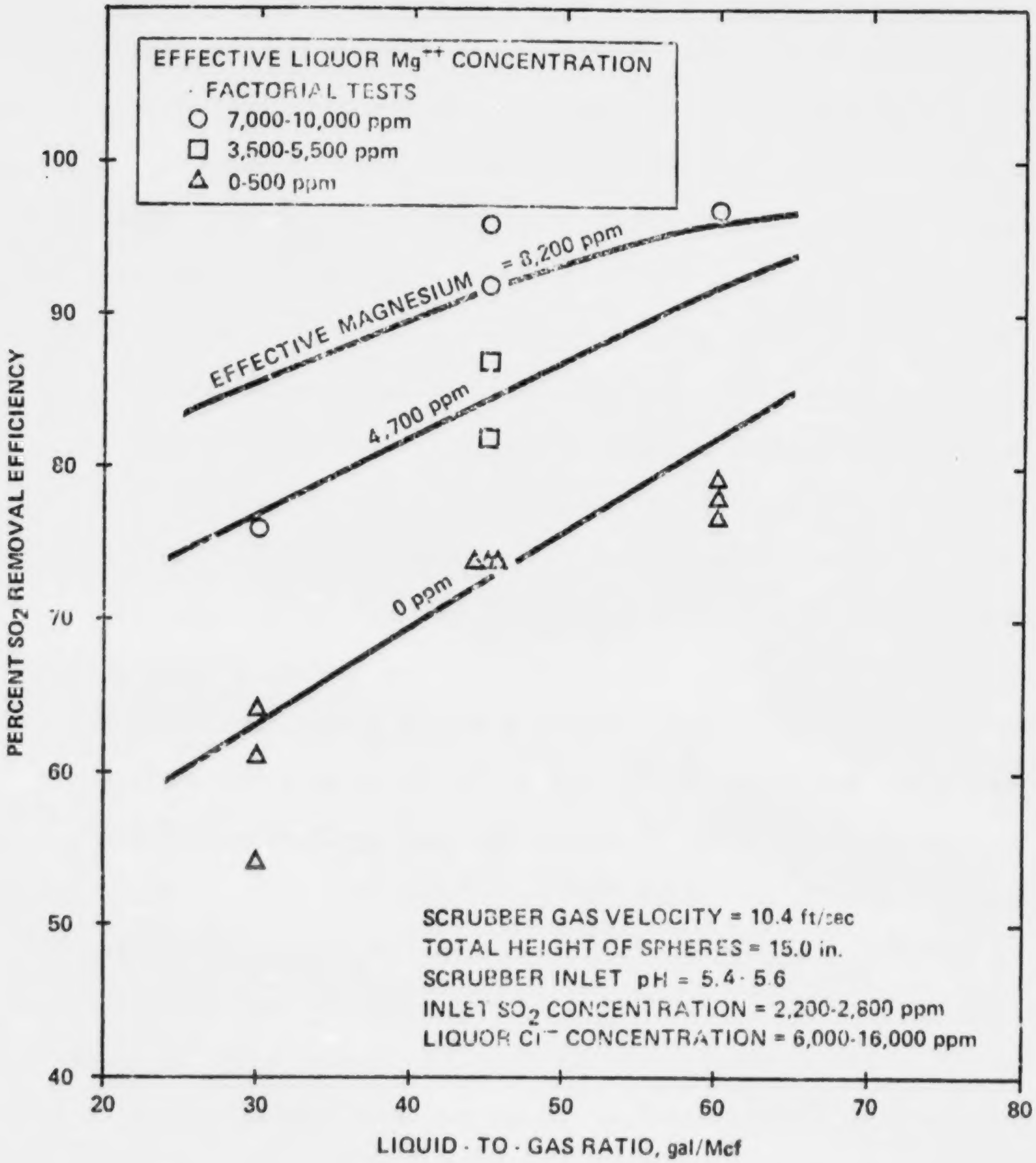
FIGURE D-6

EFFECT OF BED HEIGHT ON SO_2 REMOVAL EFFICIENCY - TCA WITH LIMESTONE

The addition of relatively small amounts of magnesium compounds (less than 1 percent by weight) to the scrubber liquor in the form of magnesium oxide, magnesium sulfate, or dolomitic lime (in lime systems) can greatly increase the SO_2 collection efficiency of the system. Magnesium compounds are much more soluble, compared to calcium, and can react rapidly in the liquid phase with SO_2. Figures D-7 through D-9 show the effect of magnesium, L/G and pH on SO_2 removal.

As another means of achieving higher overall experiences, it is possible to convert two scrubbers in series. The net overall efficiency is substantially higher than that of either stage. Figure D-10 shows the variations in two-stage absorption efficiency as a function of individual scrubber efficiency. In this case the first scrubber is a relatively inefficient (for lime or limestone without additives) scrubber, such as a venturi. When the venturi and spray tower have been operated together at the Shawnee Test Facility, SO_2 removals greater than 90 percent have been realized during short-term tests.

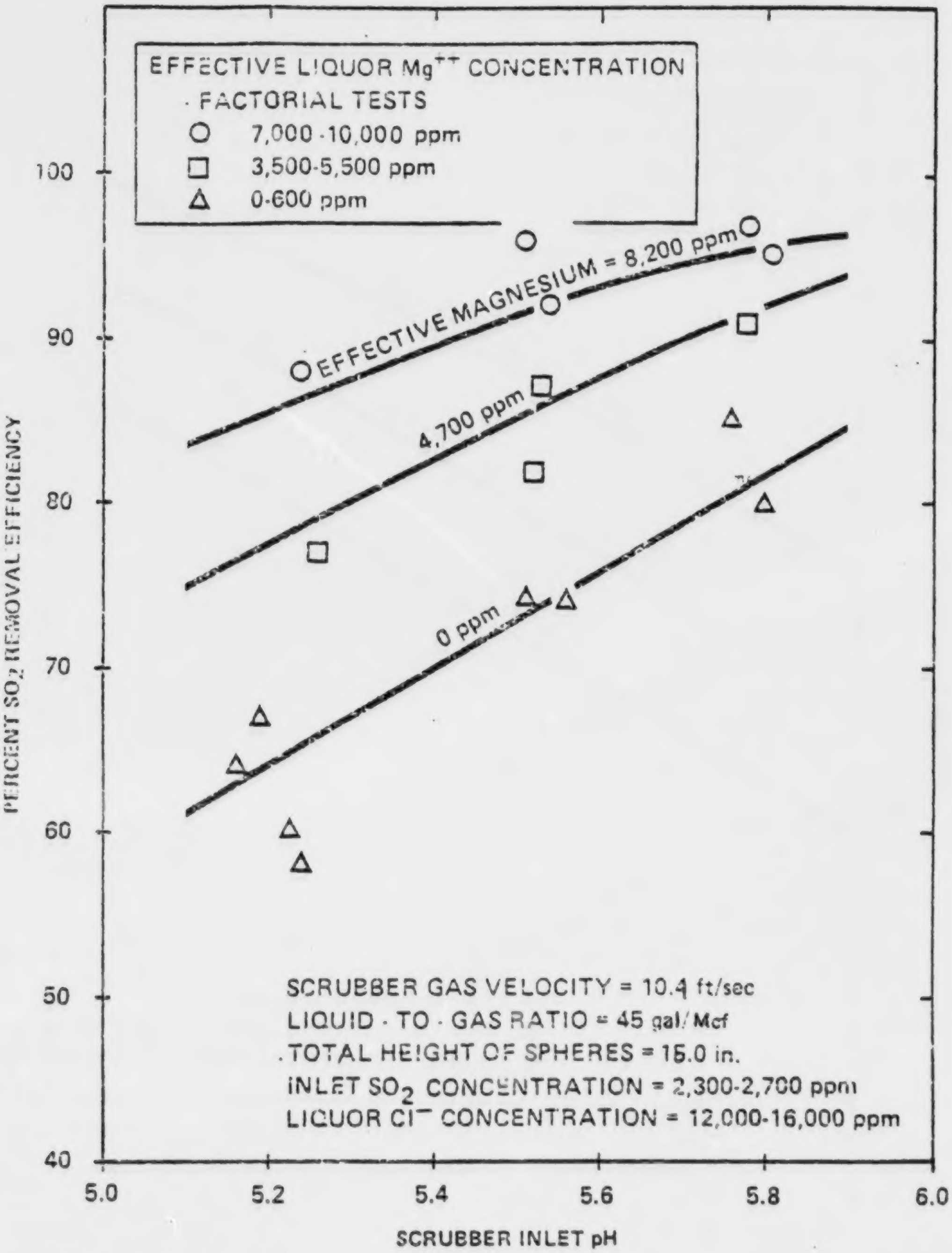
However, when two scrubbers are operated in series, the mechanical complexity increases and additional energy penalties are incurred for the greater pumping requirements and gas pressure drop. Japanese practice with oil combustion and recent U.S. developments in coal combustion indicate that the extra capital cost of two-stage scrubbing may be offset somewhat by the use of forced oxidation techniques to



Source: Bechtel, 1977.

FIGURE D-7

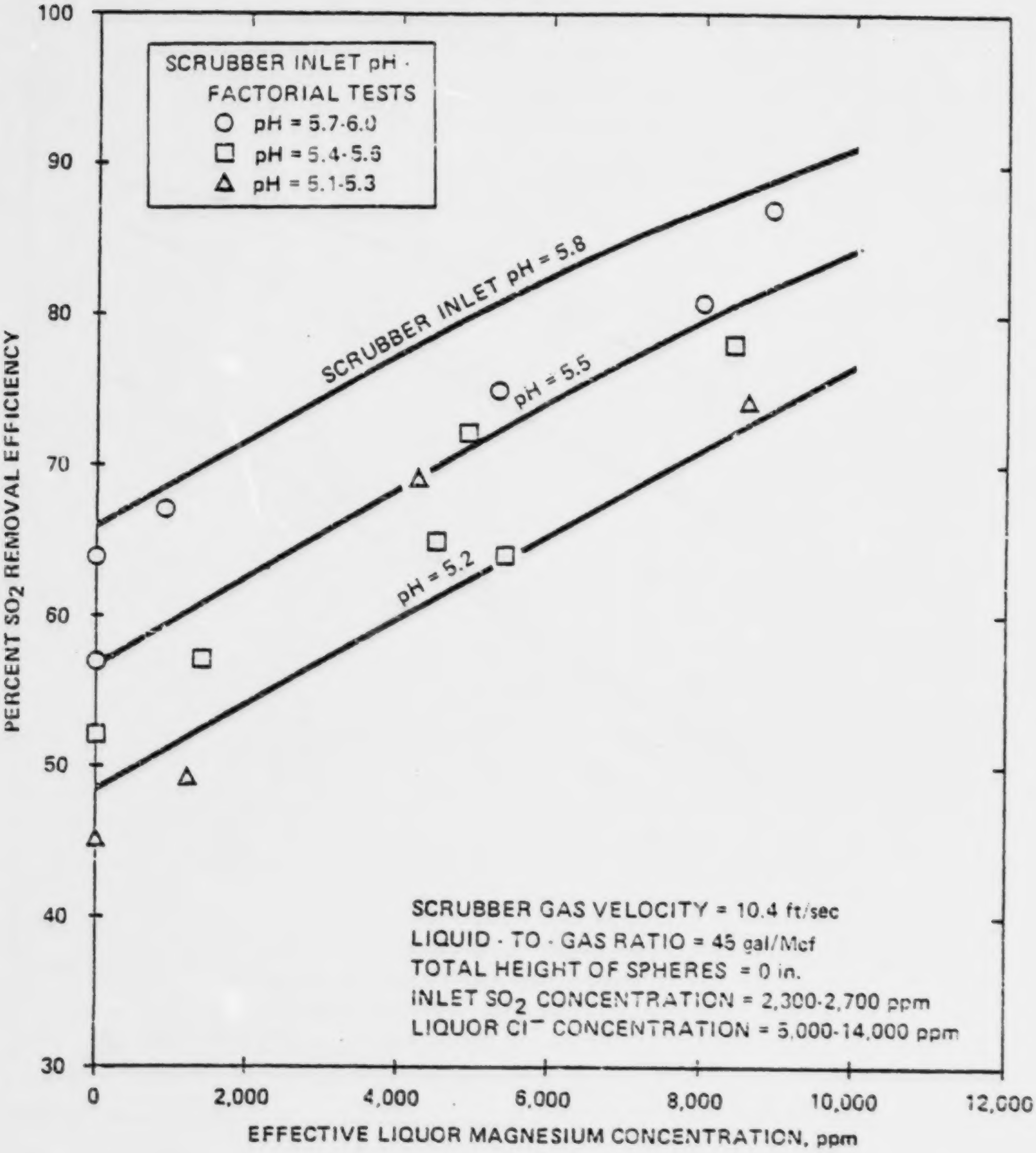
EFFECT OF LIQUID-TO-GAS RATIO ON SO_2 REMOVAL EFFICIENCY - TCA WITH LIMESTONE AND MAGNESIUM



Source: Bechtel, 1977.

FIGURE D-8

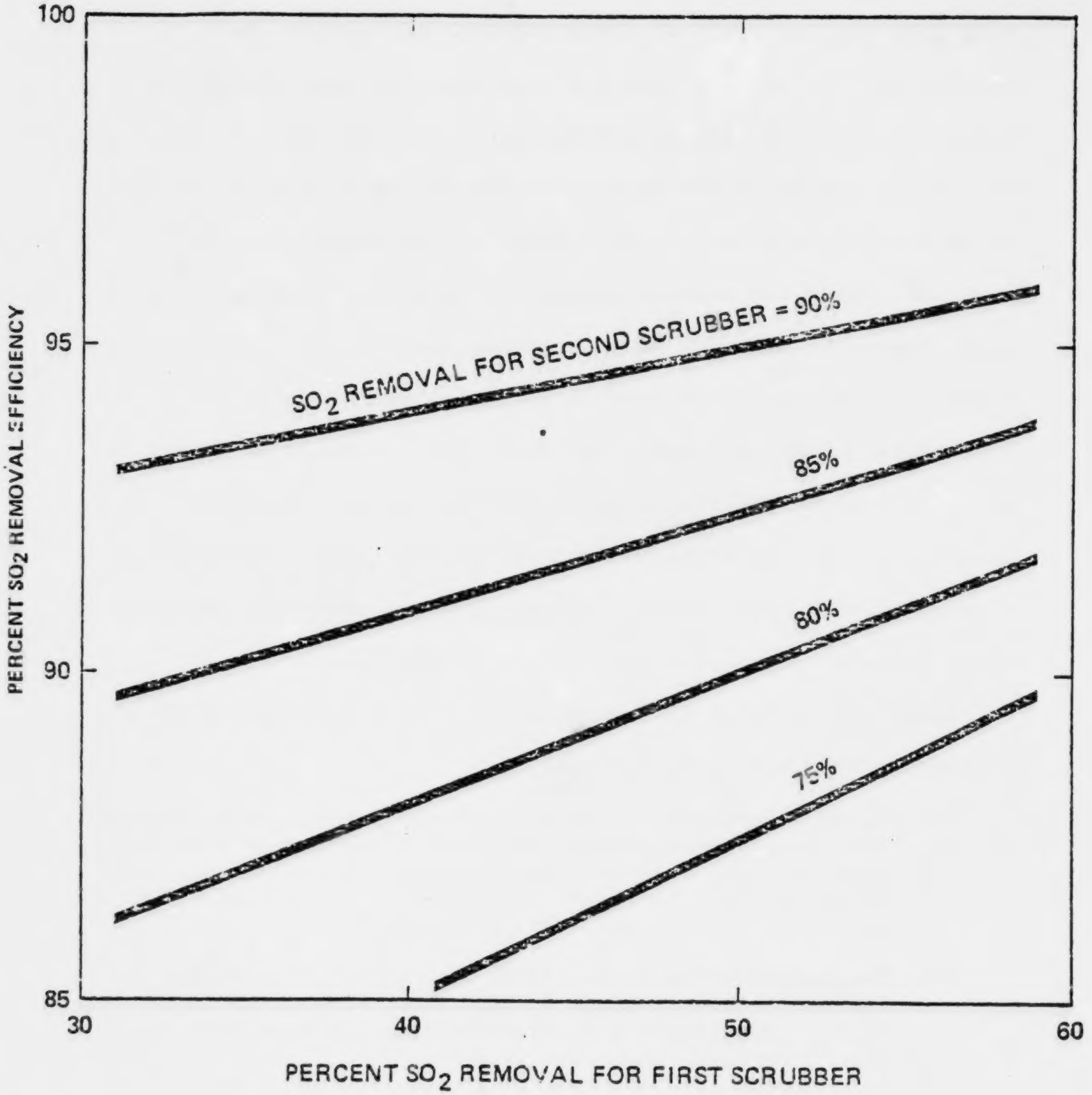
EFFECT OF SCRUBBER INLET PH ON SO_2 REMOVAL EFFICIENCY - TCA WITH LIMESTONE AND MAGNESIUM



Source: Bechtel, 1977.

FIGURE D-9

EFFECT OF MAGNESIUM ON SO_2 REMOVAL EFFICIENCY - TCA (NO SPHERES) WITH LIMESTONE



Source: Bechtel, 1977.

FIGURE D-10

SO_2 ABSORPTION EFFICIENCY FOR TWO SCRUBBERS IN SERIES bring down the high costs of sludge disposal and improve alkali utilization. In lime and limestone scrubbing, the waste product is normally a slurry of calcium sulfite, calcium sulfate (gypsum) and fly ash (if removed by the scrubber). The calcium sulfite can be oxidized to gypsum by air-slurry contact (forced oxidation). The resultant product has improved properties including higher settling rates, improved dewatering characteristics, and reduced total waste volume. One successful approach is to oxidize the slurry in the first of two scrubbing stages. The cost offset of two-stage forced oxidation does not apply to coals of lower sulfur content where oxidation and settled sludge density are normally high. The relationship between sulfur content, degree of forced oxidation, impounded sludge behavior, and cost is not yet fully quantified.

Facilities at which high removal efficiencies have been obtained are briefly described below:

(1) The Mohave Station of the Southern California Edison Company, reported SO_2 removal efficiencies of 95 percent or more with limestone, and of 98 percent with lime. The tests were conducted intermittently over 1-year on low-sulfur coal. The unit was a 170-MW equivalent, prototype scrubber.

(2) The packed module on the 115-MW Unit No. 1 at the Cholla Station of Arizona Public Service shows 92-percent removal of SO_2 using limestone slurry scrubbing. This is also a low-sulfur-coal application (0.8%).

(3) Recent tests at the Paddy's Run Station of Louisville Gas and Electric have shown SO_2 removal efficiencies in excess of 99 percent on 3-percent-sulfur coal. This extremely high removal efficiency was due to the addition of magnesium oxide to the lime slurry.

(4) Several tests were conducted at the 10-MW TVA Shawnee Pilot Plant, where SO_2 removal efficiencies of 95 to 99 percent were reported for lime-based systems, and of more than 90 percent for limestone systems. During one test run an efficiency of 96 percent on a turbulent contact absorber (TCA) unit, high-sulfur coal application, was achieved for the limestone system.

A brief summary of three lime-based systems follows: 1) the Green River facility of Kentucky Utilities, 2) the Bruce Mansfield Station of Pennsylvania Power Company, and 3) the Mohave Station of Southern California Edison. Two limestone slurry systems are also discussed: 1) the LaCygne Station of Kansas City Power and Light, and 2) Sherburne No. 1 and 2 of Northern States Power Company.

Kentucky Utilities, Green River No. 1, 2, and 3

The FGD system is installed on three boilers which generate an equivalent of 64 MW and burn coal with a sulfur content of 3.8 percent. This system is designed to remove 80 percent of the SO_2 in a turbulent contact scrubber and 99 percent of particulates. The unit started up in September 1975, and commercial operation began in the late fall of 1975. Before commercial service, the system went through an extensive four-phase, prestartup evaluation.

Sulfur dioxide removal efficiency has been well above the design value, averaging about 90 percent. After commercial startup, several relatively minor problems were encountered and corrected. Closed-loop, full-capacity operation began March 1976, with the initiation of a 6-month vendor qualification test. To date, performance of the system has been good; and mechanical reliability is excellent. Average system operability has been above 90 percent since March 1976, with the exception of a period between February and April 1977, when the unit was shut down for stack repair.

Pennsylvania Power Company, Bruce Mansfield No. 1

This two stage venturi FGD system is installed on Unit No. 1, which is rated at 839 MW and burns coal with a sulfur content between 4.5 and 5.0 percent. The FGD system was designed for 92-percent SO_2 removal and 99.8-percent particulate removal. Unit No. 1 started up in April 1976, and full commercial operation began in May 1976. Availability was reportedly very high during the first 7 months after startup; operating problems were solved without causing boiler downtime. Since then, however, the unit has experienced serious problems with the stack liner, and the load must be reduced by approximately 50 percent for about a year for liner repairs.

Two performance tests were conducted in July 1977. The results were 190 and 540 ng/J (0.44 and 1.26 lbs $SO_2/10^6$ Btu), representing 94-percent and 83-percent removal, respectively. The allowable emission rate is 300 ng/J (0.6 lbs $SO_2/10^6$ Btu). The variations in emissions were apparently due to pH fluctuations which have since been corrected.

Southern California Edison, Mohave Station

Participants in the Navaho/Mohave Power Project funded a full-scale scrubber demonstration at the Mohave Generating Station. The

170-MW demonstration facility was installed on a 790-MW boiler firing coal with an average sulfur content of 0.4 percent. Two types of scrubbers were installed for the demonstration tests: a horizontal cross-flow scrubber and a vertical countercurrent unit. The vertical module was operated both in a TCA and in a packed grid configuration. Sulfur dioxide removal efficiency was excellent for all three absorbers. Although the SO_2 inlet concentration was only 200 ppm, all three configurations were capable of removing 95 percent of the inlet SO_2. Calculated availability percentages for the horizontal and vertical modules were 81.3 and 72.8 percent, respectively. Since this was a test facility, several design changes that contributed to low availability were made during the period.

Kansas City Power and Light Company, LaCygne No. 1

The unit is rated at 820 MW and burns coal with sulfur content ranging from 5 to 6 percent. The FGD system installed in 1972 consists of eight identical scrubbing modules, each with a venturi scrubber for particulate emission control and an absorber for SO_2 control. Particulate removal efficiency is from 97 to 99 percent. The system was designed for 76-percent SO_2 removal. Actual SO_2 removal efficiency is 80 percent with seven modules operating on 729 MW. Under maximum load, the removal efficiency averaged 76.2 percent. Efficiencies under both conditions should improve now that eight modules are operating.

The FGD installation was plagued with startup problems. However, analysis reveals that nearly all of them were due to mechanical design rather than to process chemistry limitations. The availability of this system has improved steadily as solutions to the various problems have been found. The system is now one of the most reliable FGD systems on a large boiler in the United States. The availability for 1976 averaged 91 percent, and for the first half of 1977 averaged about 93 percent.

Northern States Power Company, Sherburne Station No. 1 and No. 2

Each unit has a net generating capability of 700 MW and fires a subbituminous western coal with a 28-percent moisture, 9-percent ash, and 0.8-percent sulfur content. Each system has 12 scrubber modules, 11 of which are required for full-load operation. Sulfur dioxide removal is between 50 and 55 percent, which is sufficient to meet local requirements and approximates the value for which the system was designed. Availability for Unit No. 1, which started up in March 1976, averaged 85 percent for the first 4 months of operation. During the past 12 months, availability has been in excess of 90 percent. Unit No. 2 started up in April 1977 and has shown even better startup performance. Availabilities have averaged about 95 percent for the first 4 months.

Wellman-Lord Process

The Wellman-Lord Process uses an aqueous sodium sulfite solution to absorb SO_2 and form sodium bisulfite. The solution is regenerated and SO_2 is released in an evaporator-crystallizer. The regenerated sodium sulfite is dissolved for recycle in the absorber. The concentrated SO_2 stream is recovered as liquid SO_2, sulfuric acid, or elemental sulfur. Guidelines to obtain high efficiency for Wellman-Lord Systems include:

- Installation of a prescrubber with a separate water recirculation system for final particulate control and reduction of SO_3 and chlorides.
- Use of a three to five tray absorber with an L/G of 1.0 to 1.3 l/m^3 (6 to 10 gal/1000 acf).
- A superficial gas velocity in the range of 2.7 to 3.1 m/sec (9 to 10 ft/sec).
- Maintenance of the required sodium sulfite scrubbing solution at a pH of 6.0 at the absorber inlet.
- System make-up of fresh, 20 percent sodium carbonate solution should be approximately 0.07 l/m^3 (0.5 gallon/1000 acf) per tray.
- As SO_2 inlet concentration decreases, the number of trays required to obtain high SO_2 removal should be increased.

Seven Wellman-Lord systems are operating in the United States. Six units are installed on SO_2 or Claus sulfur recovery plants. The SO_2 removal efficiency of these six is typically 90 percent or greater, and removal efficiencies in excess of 97 percent have been reported. On-stream time for the absorption area of these plants is more than 97 percent.

The No. 11 unit at the D. H. Mitchell Generating Station at Northern Indiana Public Service Company (NIPSCO) is currently the only operational Wellman-Lord system on a utility boiler in the United States. It is also the only coal-fired application in the world. The process is designed to remove at least 90 percent of the SO_2 when firing coal containing up to 3.5 percent sulfur. The supplier guarantees the mechanical soundness and product quality of the process, as well as water, electricity, and chemical consumption. The initial startup of the NIPSCO unit began July 19, 1976, and an extended shake-down period began November 28, 1976. During this period, the Unit 11 boiler operated for 121 full days and 10 partial days, whereas the SO_2 removal system operated for 71 full days and 23 partial days, and was down for 38 days. In the course of the three sustained operating periods, the absorber demonstrated the capability of greater SO_2 removal than specified. A boiler-related mishap occurred January 15, 1977, causing the unit to be shut down for repairs until May 1977. The absorber resumed operation June 13, 1977. Operation has been erratic since then, again primarily because of boiler problems. Trials began on August 29, 1977 and were successfully completed on September 15, 1977. The equipment met the guarantee covering SO_2 and particulate removal, chemical makeup, and utility usage.

Three Wellman-Lord systems are currently under construction. Two of these will be on coal-fired boilers at the San Juan Station of the Public Service Company of New Mexico. Each unit will be on a coal-fired boiler with approximately a 350-MW rating. Both units are designed for 90-percent removal of SO_2. The third unit is at ARCO/ Polymers in Monaca, Pennsylvania, where a single scrubber will receive flue gases from three coal-fired boilers with a total equivalent rating of 100 MW. The unit is designed for approximately 87.5-percent SO_2 removal.

Magnesium Oxide Systems

This process uses a magnesium oxide slurry to react with SO_2. The reaction product, magnesium sulfite, is dried and calcined to regenerate magnesium oxide. Sulfur dioxide, liberated in the regeneration step, is recovered for conversion to sulfuric acid or for reduction to elemental sulfur. Guidelines to achieve high efficiency include:

- High efficiency particulate removal should precede the absorber.
- A prescrubber should be used to remove any remaining particulates and most of the chlorides and SO_3.
- Venturi absorbers should be utilized typically operating at a pressure drop of 25 cm (10 inches) of water or greater, or Turbulent Contact Absorbers operating at approximately 20 cm (8 inches) of water pressure drop, at an L/G of 5.3 to 6.6 l/m^3 (40 to 50 gal/100 acf).
- The absorber superficial gas velocity should not exceed approximately 3.0 m/sec (10 ft/sec) range.
- The slurry pH measured at the absorber discharge should be maintained in the 6.0 to 7.5 range.

Three full-scale units have been operated in the United States: 1) Mystic Station, Unit No. 6, of Boston Edison (oil-fired); 2) Dickerson No. 3, of Potomac Electric and Power (coal-fired); and 3)

Eddystone No. 1A, of Philadelphia Electric (both coal-fired). All used fuel with 2 to 2.5-percent sulfur content. Sulfur dioxide removal efficiencies at all three locations have been in excess of 90 percent. However, in general the three units experienced serious problems which have limited operability to between 27 and 80 percent. When reviewing these operability levels, however, several points must be kept in mind:

- Sulfur dioxide collection efficiencies were frequently over 90 percent during test periods.
- Two units (Mystic and Dickerson) were trial installations, built to obtain operating data. As such, various construction materials were used that would not have been used in a full-scale plant designed for long-term operation.
- The sulfuric acid plant that was to receive SO_2 from the Eddystone MgO regeneration facility was shut down by its owner and another had to be found.
- The single regeneration facility at Rumford, Rhode Island, could not process material from the Mystic and Dickerson stations simultaneously because it was too small.
- Many problems at the Eddystone installation are related to particulate scrubbing and not to the SO_2 absorber section.
- Many design and operating problems at these installations were solved during these early programs and would not be encountered in new designs.

In the past, the MgO systems installed by Chemico (Mystic and Dickerson) and United Engineers (Eddystone) have not had overall performance guarantees. Rather, the manufacturers of certain components guaranteed them against manufacturing defects only. Now, however, Chemico is willing to guarantee the entire MgO system mechanically, as well as specifying that the unit will meet applicable SO_2 emission regulations, including a 90-percent removal efficiency.

Double Alkali Flue Gas Desulfurization Systems

Double alkali scrubbing is an indirect lime/limestone process, in which a soluble alkaline medium is used in the scrubbing vessel to react with SO_2. The scrubber effluent is then treated with lime or limestone in a reactor outside the scrubber loop, where calcium sulfites and sulfates are precipitated and the scrubbing liquor regenerated and returned to the scrubber. This system greatly reduces the problems of plugging and scaling. Various double alkali process configurations are available and are described in the full report. Guidelines to achieve high efficiency include:

- Utilization of a prescrubber with a separate water recirculating system for control of particulates and chlorides for high chloride coal (>0.04 percent Cl by weight in the coal).
- Use of a two-stage tray or packed tower absorber with an L/G in the 1.3 to 2.7 l/m^3 (10 to 20 gal/1000 acf). Typically the absorber pressure drop is 15 to 30 cm (6 to 12 inches) of water.
- The absorber scrubbing liquor pH being recycled to the absorber should be in the range 6.0 to 7.0 pH range.
- If lime regeneration is used, the reaction tank residence time should be approximately 10 minutes.
- If limestone regeneration is used, the reactor tank residence time should be approximately 30 minutes.

A number of successful bench-scale, pilot plant, and prototype double alkali systems have been tested on both industrial and utility boiler flue gas applications in the United States. The success of these programs has resulted in commitments by three separate utilities to install full-scale, double alkali systems on coal-fired boilers. As yet, however, no full-scale system is operating on utility boilers, although several are in operation on coal-fired industrial boilers.

At the Cane Run No. 6 unit of Louisville Gas and Electric, a 277-MW coal-fired unit, the double alkali system is scheduled to start up in February 1979. The unit is designed to have 200 ppm of SO_2 or less in the discharge from the scrubber, and 95-percent SO_2 removal when the sulfur content of the coal is 5 percent or greater. Coal sulfur content is expected to be between 3.5 and 4 percent.

At the A. B. Brown No. 1 installation of Southern Indiana Gas and Electric, the double alkali system will be applied to a 250-MW boiler firing coal with an average sulfur content of 3.5 percent. The unit is scheduled for startup in April 1979, and designed to remove 85 percent of the SO_2 when burning 4.5-percent sulfur coal, the maximum sulfur content expected.

At the Newton No. 1 unit of Central Illinois Public Service, the double alkali system will be installed on a 575-MW boiler firing coal with an average sulfur content of 4 percent. The unit will start up in November 1979. The design SO_2 removal efficiency is 95 percent, or less than 200 ppm in the exit gas.

Four double alkali systems have been installed on industrial coal-fired boilers. These systems have operated with high removal efficiency, ranging from 85 to 99 percent (mostly 90 to 95 percent).

While some have had mechanical problems, the systems have shown themselves reliable; generally operability has been over 90 percent. In addition, two prototype double alkali systems were operated on utility coal-fired boilers, one on low-sulfur coal and the other on high-sulfur coal. Both had SO_2 removal efficiencies above 90 percent, and their success has resulted in the design of a full-scale system that is expected to have high levels of operability and efficiency.

FGD System Efficiency Summary

Table D-1 identifies facilities at which FGD systems have removed 90 percent or more of SO_2. In addition, many of the systems listed in Appendix E are being designed for efficiencies of 90 percent or greater.

The major suppliers of systems are now offering SO_2 removal guarantees. Levels of SO_2 removal which vendors will guarantee exceed 90 percent, and in some cases 95 percent, often have a lower limit on outlet SO_2 concentration (e.g., 50 ppm). For lower sulfur coals, this lower limit, rather than efficiency, would become the basis of the guarantee. Thus existing technology is adequate for meeting a 90-percent SO_2 removal requirement.

TABLE D-1

PLANTS REPORTING 90 PERCENT OR GREATER SO_2 REMOVAL

Utility Company	Station	Unit	MW	Nature	Process	% S in fuel	SO_2 removal, %
Arizona Public Service	Cholla	No. 1	115	Full-scale	Limestone	0.4-1.0	92
	Four Corners	No. 5	160	Demonstration	Lime	0.7	95
Duquesne Light	Phillips	Nos. 1-6	410	Full-scale	Lime	1.0-2.8	90+
Louisville Gas & Electric	Cane Run	No. 4	175	Full-scale	Lime	3.5-4.0	90
	Paddy's Run	No. 6	65	Demonstration	Lime	3.5-4.0	99.5
Northern Indiana Public Service	Mitchell	No. 11	115	Demonstration	Wellman-Lord	3.2-3.5	90
Philadelphia Electric	Eddystone	No. 1	120	Demonstration	Mag-Ox	2.5	95-98
Tennessee Valley Authority	Shawnee	No. 10	10	Prototype	Lime/limestone	0.8-5.0	95-99
Boston Edison	Mystic	No. 6	150	Demonstration+	Mag-Ox	2.5	90
Detroit Edison	St. Clair	No. 6	163	Demonstration	Limestone	0.3	90-91
General Motors	Parma	No. 1-4	32	Full-scale*	Double-alkali	4.0	90+
Gulf Power	Scholz	No. 1	20	Prototype	Double-alkali	3.0	95
	Scholz	No. 1-2	20	Prototype	Chiyoda	3.0	95
	Scholz	No. 2	20	Prototype	Carbon	3.0	90+
Potomac Electric & Power	Dickerson	No. 3	95	Demonstration	Mag-Ox	2.0	90
Southern California Edison	Mohave	No. 1	170	Demonstration	Limestone	0.6	95
	Mohave	No. 2	170	Demonstration	Lime	0.6	95
U.S. Air Force	Rickenbacker	No. 1-9	20	Full-scale**	Lime	3.6	99
Kentucky Utilities	Green River	No. 1-3	64	Full-scale	Lime	3.8	90+

* Industrial
** Military Base
+ Oil Fired

Source: PEDCO, 1977e.

NOTE: Most reported SO_2 removal data is based on intermittent manual tests.

APPENDIX E

PLANNED AND OPERATING FGD SYSTEMS

This appendix gives a list of planned and operating FGD systems. The data were obtained from the PEDCo FGD Status Reports.

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APPENDIX E-1

FLUE GAS DESULFURIZATION SYSTEMS ON COAL FIRED UTILITY BOILERS IN THE U.S.

COMPANY	UNIT	LOCATION	FGD PROCESS	CAPACITY, MEGAWATTS	APPLICATION	FUEL		STATUS	STARTUP DATE
						TYPE	SULFUR CONTENT, PERCENT		
Alabama Electric Cooperative, Inc.	Tombigbee No. 2	Jackson, AL	Limestone scrubbing	225	New	Coal	0.8-1.5	Under construction	6-78
Alabama Electric Cooperative, Inc.	Tombigbee No. 3	Jackson, AL	Limestone scrubbing	225	New	Coal	0.8-1.5	Contract awarded	6-79
Allegheny Power System, Inc.	Pleasants No. 1	Bellmont, WV	Lime scrubbing	625	New	Coal	4.5-(Max)	Under construction	3-79
Allegheny Power System, Inc.	Pleasants No. 2	Bellmont, WV	Lime scrubbing	625	New	Coal	4.5-(Max)	Under construction	3-80
Arizona Electric Power Cooperative, Inc.	Apache No. 2	Cochise, AZ	Limestone scrubbing	200	New	Coal	0.5-0.8	Under construction	6-79
Arizona Electric Power Cooperative, Inc.	Apache No. 3	Cochise, AZ	Limestone scrubbing	200	New	Coal	0.5-0.8	Under construction	4-79
Arizona Public Service Company	Cholla No. 1	Joseph City, AZ	Limestone scrubbing	115	Retrofit	Coal	0.44-1	Operational	10-[illegible]
Arizona Public Service Company	Cholla No. 2	Joseph City, AZ	Limestone scrubbing	250	New	Coal	0.44-1	Under construction	6-[illegible]
Arizona Public Service Company	Cholla No. 4	Joseph City, AZ	Limestone scrubbing	350	Retrofit	Coal	0.44-1	Under consideration	6-80
Arizona Public Service Company	Four Corners No. 4	Farmington, NM	Undetermined	755	Retrofit	Coal	0.7	Under consideration	Und.
Arizona Public Service Company	Four Corners No. 5B	Farmington, NM	Undetermined	755	Retrofit	Coal	0.7	Under consideration	Und.
Basin Electric Power Cooperative	Antelope Valley No. 1	Beulah, ND	Lime/Flyash scrubbing	450	New	Lignite	1.0	Under consideration	[illegible]
Basin Electric Power Cooperative	Antelope Valley No. 2	Beulah, ND	Undetermined	450	New	Lignite	1.0	Under consideration	8[illegible]
Basin Electric Power Cooperative	Laramie River No. 1	Wheatland, WY	Limestone scrubbing	550	New	Coal	0.8	Contract awarded	4-[illegible]
Basin Electric Power Cooperative	Laramie River No. 2	Wheatland, WY	Limestone scrubbing	550	New	Coal	0.8	Contract awarded	10-[illegible]
Basin Electric Power Cooperative	Laramie River No. 3	Wheatland, WY	Undetermined	550	New	Coal	0.8	Under consideration	[illegible]
Big Rivers Electric Corporation	Reid No. 2	Sebree, KY	Lime scrubbing	[illegible]	New	Coal	3.5-4.0	Under construction	11-[illegible]
Brazos Electric Power Cooperative, Inc.	Atacosa McMullen No. 1	San Miguel, TX	Limestone scrubbing	400	New	Lignite	1.67	Contract awarded	12-[illegible]
Central Illinois Light Company	Duck Creek No. 1	Canton, IL	Limestone scrubbing	400	New	Coal	2.5-3.0	Under construction	[illegible]
Central Illinois Light Company	Duck Creek No. 2	Canton, IL	Limestone scrubbing	400	New	Coal	2.5-3.0	Under consideration	[illegible]
Central Illinois Public Service	Newton No. 1	Newton, IL	Double alkali scrubbing	575	New	Coal	2.8-3.2	Under construction	[illegible]
Cincinnati Gas & Electric Company	East Bend No. 2	Rabbit Hash, KY	Undetermined	600	New	Coal	Und.	Under consideration	[illegible]
Colorado Ute Electric Assn., Inc.	Craig No. 1	Craig, CO	Limestone scrubbing	450	New	Coal	0.45	Contract awarded	[illegible]
Colorado Ute Electric Assn., Inc.	Craig No. 2	Craig, CO	Limestone scrubbing	450	New	Coal	0.45	Contract awarded	3-79
Columbus & Southern Ohio Electric Co.	Conesville No. 5	Conesville, OH	Lime scrubbing	400	New	Coal	4.5-4.9	Operational	2-7[illegible]
Columbus & Southern Ohio Electric Co.	Conesville No. 6	Conesville, OH	Lime scrubbing	400	New	Coal	4.5-4.9	Under construction	1-7[illegible]
Columbus & Southern Ohio Electric Co.	Poston No. 5	Athens, OH	Undetermined	375	New	Coal	2.5	Under consideration	81
Columbus & Southern Ohio Electric Co.	Poston No. 6	Athens, OH	Undetermined	375	New	Coal	2.5	Under consideration	83
Commonwealth Edison Company	Powerton No. 51	Pekin, IL	Limestone scrubbing	425	Retrofit	Coal	3.6	Under construction	12-79
Commonwealth Edison Company	Will County No. 1	Romeoville, IL	Limestone scrubbing	167	Retrofit	Coal	4.0	Operational	2-72
Duquesne Light Company	Elrama Power Station	Elrama, PA	Lime scrubbing	510	Retrofit	Coal	1.0-2.8	Operational	10-75
Duquesne Light Company	Phillips Power Station	South Height, PA	Lime scrubbing	410	Retrofit	Coal	1.0-2.8	Operational	1-75
East Kentucky Power Cooperative, Inc.	Spurlock Generating Plant No. 2	Maysville, KY	Undetermined	500	New	Coal	Und.	Under consideration	3-80
Indianapolis Power & Light Company	Petersburg No. 3	Petersburg, IN	Limestone scrubbing	530	New	Coal	3.0-3.5	Under construction	9-77
Indianapolis Power & Light Company	Petersburg No. 4	Petersburg, IN	Limestone scrubbing	530	New	Coal	3.5	Under consideration	4-82
Kansas City Power & Light Company	Hawthorn No. 3	Kansas City, MO	Lime scrubbing	140	Retrofit	Coal	0.5-3.5	Operational	11-72
Kansas City Power & Light Company	Hawthorn No. 4	Kansas City, MO	Lime scrubbing	100	Retrofit	Coal	0.5-3.5	Operational	8-72
Kansas City Power & Light Company	La Cygne No. 1	La Cygne, KS	Limestone scrubbing	820	New	Coal	5.0	Operational	2-73
Kansas Power & Light Company	Jeffery No. 1	St. Mary, KS	Limestone scrubbing	680	New	Coal	0.30	Under construction	6-78
Kansas Power & Light Company	Jeffery No. 2	St. Mary, KS	Limestone scrubbing	680	New	Coal	0.30	Under construction	6-79
Kansas Power & Light Company	Lawrence No. 4	Lawrence, KS	Limestone scrubbing	125	Retrofit	Coal	0.5	Operational Under	12-68
Kansas Power & Light Company	Lawrence No. 5	Lawrence, KS	Limestone scrubbing	400	New	Coal	0.5	Operational/~~Swing~~ Mod.	6-78
Kentucky Utilities Company	Green River Nos. 1, 2, 3	Central City, KY	Lime scrubbing	64	Retrofit	Coal	3.8	Operational	9-75
Louisville Gas & Electric Company	Cane Run No. 4	Louisville, KY	Lime scrubbing	178	Retrofit	Coal	3.5-4.0	Operational	8-75
Louisville Gas & Electric Company	Cane Run No. 5	Louisville, KY	Lime scrubbing	183	Retrofit	Coal	3.5-4.0	Under construction	12-77
Louisville Gas & Electric Company	Cane Run No. 6	Louisville, KY	Double alkali scrubbing	277	Retrofit	Coal	3.5-4.0	Contract awarded	2-79
Louisville Gas & Electric Company	Mill Creek No. 1	Louisville, KY	Lime scrubbing	330	Retrofit	Coal	3.5-4.0	Under consideration	1-82
Louisville Gas & Electric Company	Mill Creek No. 2	Louisville, KY	Lime scrubbing	330	Retrofit	Coal	3.5-4.0	Under consideration	1-81
Louisville Gas & Electric Company	Mill Creek No. 3	Louisville, KY	Lime scrubbing	425	New	Coal	3.5-4.0	Under construction	12-77
Louisville Gas & Electric Company	Mill Creek No. 4	Louisville, KY	Lime scrubbing	425	New	Coal	3.5-4.0	Contract awarded	6-80
Louisville Gas & Electric Company	Paddys Run No. 6	Louisville, KY	Lime scrubbing	65	Retrofit	Coal	3.5-4.0	Operational	4-73
Minnesota Power & Light Company	Clay Boswell No. 4	Cohasset, MN	Lime/Flyash scrubbing	500	New	Coal	0.8	Letter of intent	80
Minnkota Power Cooperative Inc.	Milton R. Young No. 2	Center, ND	Lime/Flyash scrubbing	450	New	Lignite	0.7	Under construction	8-77
Montana Power Company	Colstrip No. 1	Colstrip, MT	Lime/Flyash scrubbing	360	New	Coal	0.8	Operational	10-75
Montana Power Company	Colstrip No. 2	Colstrip, MT	Lime/Flyash scrubbing	360	New	Coal	0.8	Operational	7-76
Montana Power Company	Colstrip No. 3	Colstrip, MT	Lime/Flyash scrubbing	700	New	Coal	0.7	Contract awarded	7-80
Montana Power Company	Colstrip No. 4	Colstrip, MT	Lime/Flyash scrubbing	700	New	Coal	0.7	Contract awarded	7-81

FLUE GAS DESULFURIZATION SYSTEMS ON COAL FIRED UTILITY BOILERS IN THE U.S.

COMPANY	UNIT	LOCATION	FGD PROCESS	CAPACITY, MEGAWATTS	APPLICATION	FUEL		STATUS	STARTUP DATE
						TYPE	SULFUR CONTENT, PERCENT		
Nevada Power Company	Harry Allen Station No. 1	Las Vegas, NV	Undetermined	500	New	Coal	Und.	Under consideration	6-83
Nevada Power Company	Harry Allen Station No. 2	Las Vegas, NV	Undetermined	500	New	Coal	Und.	Under consideration	6-84
Nevada Power Company	Harry Allen Station No. 3	Las Vegas, NV	Undetermined	500	New	Coal	Und.	Under consideration	6-85
Nevada Power Company	Harry Allen Station No. 4	Las Vegas, NV	Undetermined	500	New	Coal	Und.	Under consideration	6-86
Nevada Power Company	Reid Gardner No. 1	Moapa, NV	Sodium carbonate scrubbing	125	Retrofit	Coal	0.5-1.0	Operational	4-74
Nevada Power Company	Reid Gardner No. 2	Moapa, NV	Sodium carbonate scrubbing	125	Retrofit	Coal	0.5-1.0	Operational	4-74
Nevada Power Company	Reid Gardner No. 3	Moapa, NV	Sodium carbonate scrubbing	125	New	Coal	0.5-1.0	Operational	7-76
Nevada Power Company	Reid Gardner No. 4	Moapa, NV	Sodium carbonate scrubbing	125	New	Coal	0.5-1.0	Letter of intent	Und.
Nevada Power Company	Warner Valley Station No. 1	St. George, UT	Undetermined	250	New	Coal	Und.	Under consideration	6-82
Nevada Power Company	Warner Valley Station No. 2	St. George, UT	Undetermined	250	New	Coal	Und.	Under consideration	6-83
New England Electric System	Brayton Point No. 3	Somerset, MA	Undetermined regenerative	650	Retrofit	Coal	3.0	Under consideration	Und.
Niagara Mohawk Power Corporation	Charles R. Huntley No. 6	Buffalo, NY	Aqueous carbonate scrubbing	100	Retrofit	Coal	2.5-4.5	Contract awarded	[illegible]
Northern Indiana Public Service Company	Bailly No. 7	Chesterton, IN	Undetermined	190	Retrofit	Coal	3	Under consideration	Und.
Northern Indiana Public Service Company	Bailly No. 8	Chesterton, IN	Undetermined	400	Retrofit	Coal	3	Under consideration	Und.
Northern Indiana Public Service Company	D. H. Mitchell No. 11	Gary, IN	Wellman Lord	115	Retrofit	Coal	3.2-3.5	Operational	[illegible]
Northern Indiana Public Service Company	Sherburne County Station No. 1	Becker, MN	Limestone scrubbing	710	New	Coal	0.8	Operational	[illegible]
Northern Indiana Public Service Company	Sherburne County Station No. 2	Becker, MN	Limestone scrubbing	680	New	Coal	0.8	Operational	4-77
Northern Indiana Public Service Company	Sherburne County Station No. 3	Becker, MN	Undetermined	860	New	Coal	0.8	Requesting/Eval. bids	5-81
Northern Indiana Public Service Company	Sherburne County Station No. 4	Becker, MN	Undetermined	860	New	Coal	0.8	Requesting/Eval. bids	5-81
Otter Tail Power Company	Coyote No. 1	Beulah, ND	Undetermined	400	New	Lignite	0.9	Under consideration	5-81
Pacific Power & Light Company	Jim Bridger No. 4	Rock Springs, NY	Sodium carbonate scrubbing	509	New	Coal	0.50-(Avg)	Contract awarded	[illegible]
Pennsylvania Power Company	Bruce Mansfield No. 1	Shippingport, PA	Lime scrubbing	835	New	Coal	4.7	Operational	[illegible]
Pennsylvania Power Company	Bruce Mansfield No. 2	Shippingport, PA	Lime scrubbing	835	New	Coal	4.7	Under construction	10-77
Pennsylvania Power Company	Bruce Mansfield No. 3	Shippingport, PA	Lime scrubbing	835	New	Coal	4.7	Contract awarded	[illegible]
Philadelphia Electric Company	Cromby	Phoenixville, PA	Magnesium oxide scrubbing	150	Retrofit	Coal	2-4	Under consideration	6-80
Philadelphia Electric Company	Eddystone No. 1A	Eddystone, PA	Magnesium oxide scrubbing	120	Retrofit	Coal	2.5	Operational	[illegible]
Philadelphia Electric Company	Eddystone No. 1B	Eddystone, PA	Magnesium oxide scrubbing	240	Retrofit	Coal	2.5	Letter of intent	[illegible]
Philadelphia Electric Company	Eddystone No. 2	Eddystone, PA	Magnesium oxide scrubbing	336	Retrofit	Coal	2.4	Under consideration	[illegible]
Potomac Electric Power Company	Dickerson No. 1	Dickerson, MD	Undetermined	190	Retrofit	Coal	Und.	Under consideration	[illegible]
Potomac Electric Power Company	Dickerson No. 2	Dickerson, MD	Undetermined	190	Retrofit	Coal	Und.	Under consideration	79
Public Service Company of New Mexico	San Juan No. 1	Waterflow, NM	Wellman Lord	375	New	Coal	0.8	Under construction	11-77
Public Service Company of New Mexico	San Juan No. 2	Waterflow, NM	Wellman Lord	340	Retrofit	Coal	0.8	Under construction	11-77
Public Service Company of New Mexico	San Juan No. 3	Waterflow, NM	Undetermined regenerative	500	New	Coal	0.8	Letter of intent	1-79
Public Service Company of New Mexico	San Juan No. 4	Waterflow, NM	Undetermined regenerative	500	New	Coal	0.8	Under consideration	5-81
Public Service Company of Indiana, Inc.	Gibson No. 3	Gibson County, IN	Undetermined	650	New	Coal	3.3	Requesting/Eval. bids	78
Public Service Company of Indiana, Inc.	Gibson No. 4	Gibson County, IN	Undetermined	650	New	Coal	3.3	Requesting/Eval. bids	79
Salt River Project(1)	Coronado No. 1	St. Johns, AZ	Limestone scrubbing	350	New	Coal	1.0-(Max)	Contract awarded	4-79
Salt River Project(1)	Coronado No. 2	St. Johns, AZ	Limestone scrubbing	350	New	Coal	1.0-(Max)	Contract awarded	[illegible]
Salt River Project(1)	Coronado No. 3	St. Johns, AZ	Limestone scrubbing	350	New	Coal	1.0-(Max)	Under consideration	87
South Carolina Pub. Serv. Authority	Winyah No. 2	Georgetown, SC	Limestone scrubbing	280	New	Coal	1.0	Under construction	7-77
Southern Illinois Power Cooperative	Marion No. 4	Marion, IL	Limestone scrubbing	180	New	Coal	4.5-5.0	Under construction	6-78
Southern Indiana Gas & Electric Company	A. B. Brown No. 1	West Franklin, IN	Double alkali scrubbing	250	New	Coal	3.75	Contract awarded	4-79
South Mississippi Electric Power Assoc.	R. D. Morrow No. 1	Hattiesburg, MS	Limestone scrubbing	180	New	Coal	1.0	Under construction	11-77
South Mississippi Electric Power Assoc.	R. D. Morrow No. 2	Hattiesburg, MS	Limestone scrubbing	180	New	Coal	1.0	Under construction	8-78
Springfield City Utilities	Southwest No. 1	Springfield, MO	Limestone scrubbing	200	New	Coal	3.5	Operational	4-77
Tennessee Valley Authority	Shawnee No. 10A	Paducah, KY	Lime/Limestone scrubbing	10	Retrofit	Coal	2.9	Operational	4-72
Tennessee Valley Authority	Shawnee No. 10B	Paducah, KY	Lime/Limestone scrubbing	10	Retrofit	Coal	2.9	Operational	4-72
Tennessee Valley Authority	Widows Creek No. 8	Bridgeport, AL	Limestone scrubbing	550	Retrofit	Coal	3.7	Operational	5-77
Texas Power & Light Company	Sandow No. 4	Rockdale, TX	Limestone scrubbing	545	New	Lignite	Und.	Requesting/Eval. bids	7-80
Texas Power & Light Company	Twin Oaks No. 1	Robertson Co., TX	Undetermined	750	New	Lignite	Und.	Under consideration	8-83
Texas Power & Light Company	Twin Oaks No. 2	Robertson Co., TX	Undetermined	750	New	Lignite	Und.	Under consideration	9-84
Texas Utilities Company	Forest Grove No. 1	Athens, TX	Undetermined	750	New	Lignite	Und.	Under consideration	81
Texas Utilities Company	Martin Lake No. 1	Tatum, TX	Limestone scrubbing	793	New	Coal	1.0	Under construction	10-77
Texas Utilities Company	Martin Lake No. 2	Tatum, TX	Limestone scrubbing	793	New	Coal	1.0	Under construction	2-78
Texas Utilities Company	Martin Lake No. 3	Tatum, TX	Limestone scrubbing	793	New	Coal	1.0	Contract awarded	12-78
Texas Utilities Company	Martin Lake No. 4	Tatum, TX	Limestone scrubbing	793	New	Coal	1.0	Contract awarded	[illegible]
Texas Utilities Company	Monticello No. 3	Mt. Pleasant, TX	Limestone scrubbing	750	New	Lignite	1.0	Under construction	2-78
United Power Association	Coal Creek No. 1	Underwood, ND	Lime scrubbing	545	New	Lignite	0.63	Contract awarded	[illegible]
United Power Association	Coal Creek No. 2	Underwood, ND	Lime scrubbing	545	New	Lignite	0.63	Contract awarded	11-79
Utah Power & Light Company	Emery No. 1	Emery County, UT	Lime scrubbing	400	New	Coal	0.5	Under construction	[illegible]
Utah Power & Light Company	Huntington No. 1	Price, UT	Lime scrubbing	415	New	Coal	0.5	Under construction	12-77
Wisconsin Power & Light Co.	Columbia No. 2	Portage, WI	Lime/Flyash scrubbing	527	New	Coal	0.8	Letter of intent	1-80

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(1) Salt River Project Agricultural Improvement & Power District
[illegible], June 1977.

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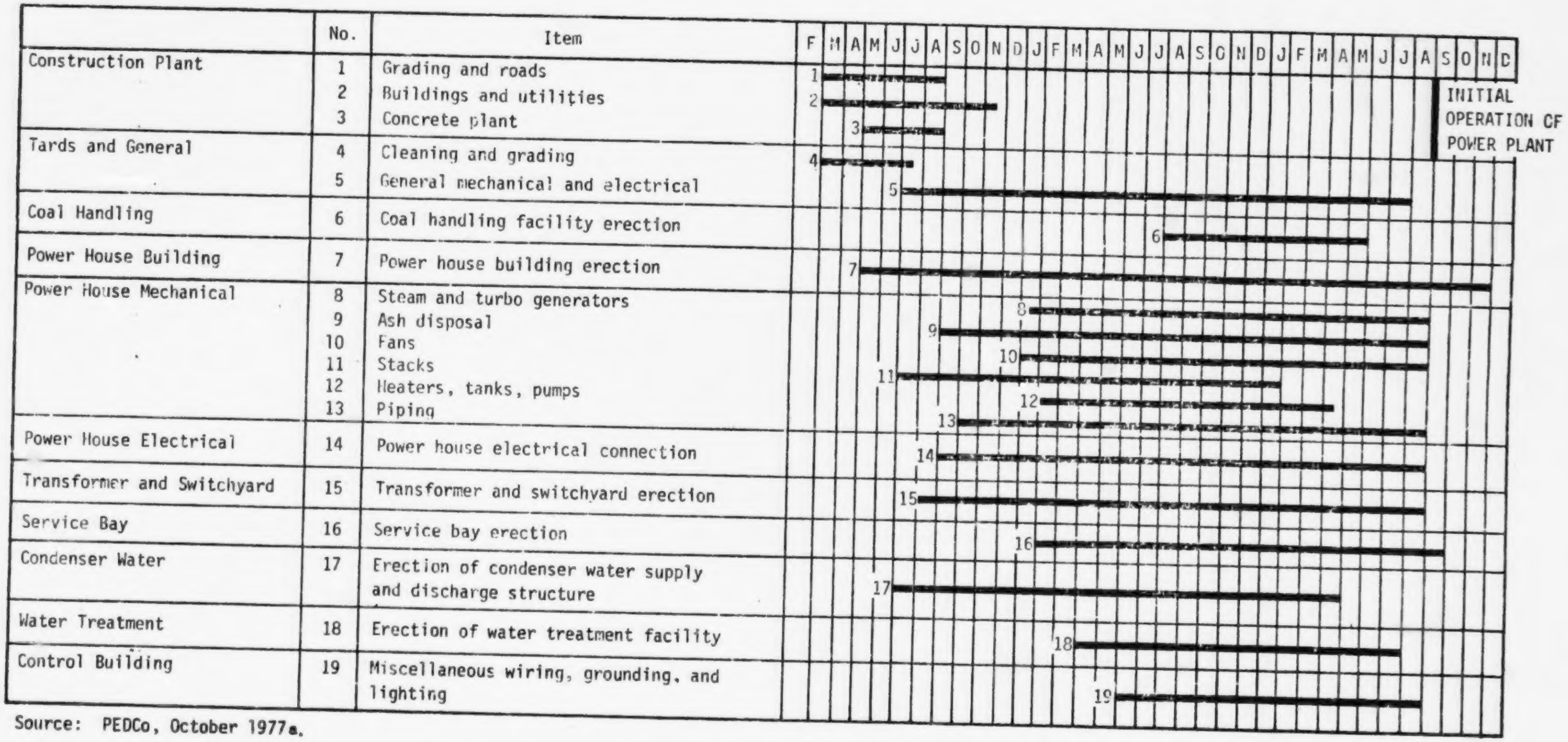
APPENDIX F

CONSTRUCTION SCHEDULE

This appendix presents two hypothetical power plant construction schedules, one with FGD and one without FGD. While this comparison shows 6 months' difference in a 3-year schedule (excluding preliminary design about 18 to 24 months) the effect can be varied by increasing or decreasing the construction force size.

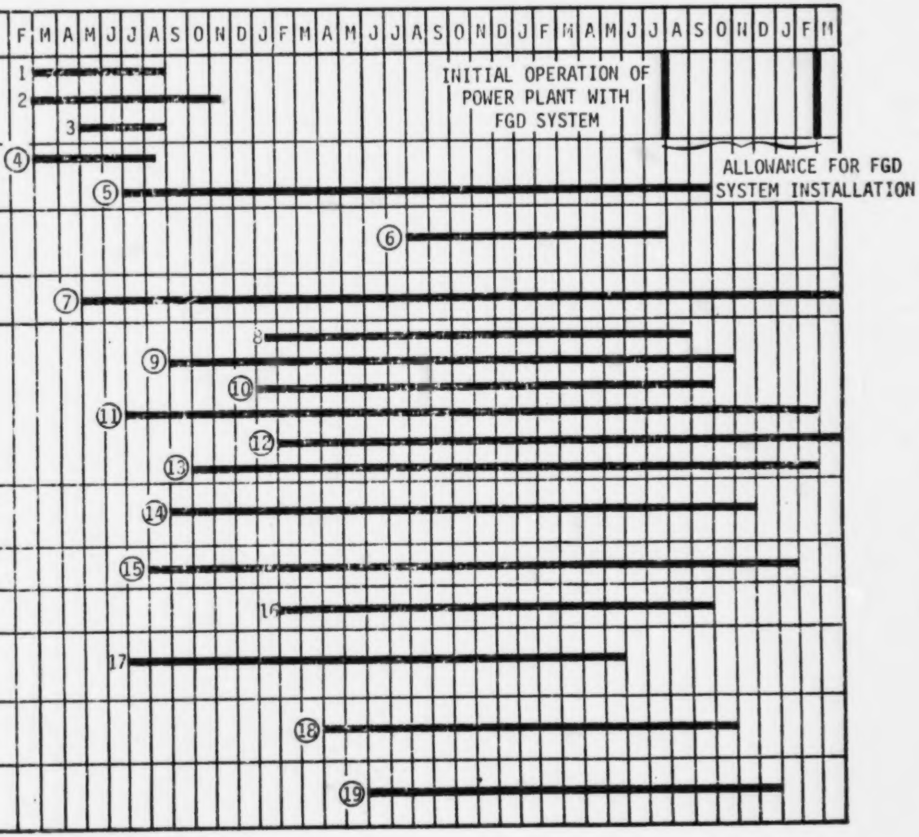


	No.	Item
Construction Plant	1	Grading and roads
	2	Buildings and utilities
	3	Concrete plant
Tards and General	4	Cleaning and grading
	5	General mechanical and electrical
Coal Handling	6	Coal handling facility erection
Power House Building	7	Power house building erection
Power House Mechanical	8	Steam and turbo generators
	9	Ash disposal
	10	Fans
	11	Stacks
	12	Heaters, tanks, pumps
	13	Piping
Power House Electrical	14	Power house electrical connection
Transformer and Switchyard	15	Transformer and switchyard erection
Service Bay	16	Service bay erection
Condenser Water	17	Erection of condenser water supply and discharge structure
Water Treatment	18	Erection of water treatment facility
Control Building	19	Miscellaneous wiring, grounding, and lighting

Source: PEDCo, October 1977a.

FIGURE F-1
CONSTRUCTION SCHEDULE FOR A TYPICAL (500-MW) POWER PLANT

	No.	Item
Construction Plant	1 2 3	Grading and roads Buildings and utilities Concrete plant
Tards and General	④ ⑤	Cleaning and grading General mechanical and electrical
Coal and Limestone Handling	⑥	Coal and limestone handling facility erection
Power House and FGD Building	⑦	Power hours and FGD building erection
Power House and FGD Mechanical	8 ⑨ ⑩ ⑪ ⑫ ⑬	Steam and turbo generators Ash and sludge disposal Fans Stacks Heaters, tanks, pumps Piping
Power House and FGD Electrical	⑭	Power house and FGD electrical connection
Transformer and Switchyard	⑮	Transformer and switchyard erection
Service Bay	16	Service bay erection
Condenser Water	17	Erection of condenser water supply and discharge structure
Water and Waste Treatment	⑱	Construction of water and waste treatment facility
Control Building	⑨	Miscellaneous wiring, grounding, and lighting



○ These activities will delay the schedule by about 6 months for a power plant equipped with an FGD system.

Source: PEDCo, October 1977a.

FIGURE F-2
CONSTRUCTION SCHEDULE FOR A TYPICAL POWER PLANT EQUIPPED WITH FGD SYSTEM

APPENDIX G

ASSUMED PARAMETERS IN FGD COSTS

The following appendix gives the assumptions made by PEDCo in developing the project FGD costs.

TABLE G-1

FLUE GAS DESULFURIZATION UNITS

<table>
<tr><th>Model plant parameters</th><th colspan="4">Characteristics and assumptions</th></tr>
<tr><td>Plant capacities, MW</td><td colspan="4">25, 100, 200, 500, and 1000 (single boilers)</td></tr>
<tr><td>Plant status</td><td colspan="4">New</td></tr>
<tr><td>Coal characteristics</td><td colspan="4">(See Table G-2)</td></tr>
<tr><td>SO_2 control requirements</td><td colspan="4">(1) The existing NSPS of 520ng/J (1.2 lb SO_2/MW Btu) heat input.
(2) 90% of SO_2 removal by FGD on a typical coal of 3.5% sulfur and a typical coal of 7% sulfur.
(3) 220ng/J 0.5 lbs. SO_2 emissions MM Btu heat input.</td></tr>
<tr><td>Location</td><td colspan="4">Midwest location - East North Central Region.</td></tr>
<tr><td>Boiler data</td><td colspan="4"></td></tr>
<tr><td>Capacity factor</td><td colspan="4">Assumed 0.65 for all plants</td></tr>
<tr><td>Heat rates, flue gas flow rates and remaining life</td><td>Capacity, MW</td><td>Heat rate[1], Btu/kWh</td><td>Flue gas[1] flow rate, acfm/MW</td><td>Remaining life, yr</td></tr>
<tr><td></td><td>25</td><td>10,000</td><td>3,500</td><td>35</td></tr>
<tr><td></td><td>100</td><td>9,500</td><td>3,350</td><td>35</td></tr>
<tr><td></td><td>200</td><td>9,200</td><td>3,175</td><td>35</td></tr>
<tr><td></td><td>500</td><td>9,000</td><td>3,080</td><td>35</td></tr>
<tr><td></td><td>1,000</td><td>8,700</td><td>3,000</td><td>35</td></tr>
<tr><td>Flue gas temperatures</td><td colspan="4">Assumed 310°F for all plants.</td></tr>
</table>

[1] Detailed Cost Estimates for Advanced Effluent Desulfurization Processes, prepared for Control Systems Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, under Interagency Agreement EPA IAG-134(d) Part A, by G. C. McGlanery, et al., Tennessee Valley Authority, pp. 60,66. May 1974.

Source: PEDCo., 1977.

TABLE G-1

(Continued)

Model plant parameters (August 1980)	Characteristics and assumptions
Operating cost factors	
Raw materials[1]	
Lime cost	$40.20/ton
Limestone cost	$9.10/ton
Pulverized limestone cost	$15.35/ton
Soda ash cost	$105.00/ton
Salt cake credit	$50.00/ton
Sulfuric acid credit	$25.00/ton
Magnesium oxide cost	$185.00/ton
Coke cost	$125.00/ton
Fuel oil cost	$15.00/bbl
Electricity cost	25 mills/kWh
Capital recovery	18.75 percent of total capital investment
Taxes and insurance	4 percent of total capital investment
Sludge disposal	On-site disposal of stabilized sludge
Redundancy requirements	
25 MW	No spare module
100, 200, 500, 1000 MW	1 spare module

[1] Costs were obtained from distributors of the various products and escalated to August 1980 dollars.

Source: PEDCo, 1977.

TABLE G-2

ANALYSES OF COALS USED AS THE COST ESTIMATING BASIS

Coal Type	Total sulfur (%)	Pyritic sulfur (%)	Ash (%)	Heating Value Btu/lb
Eastern bituminous	6.39	4.6	14	12,000
Eastern bituminous	3.48	2.49	14	12,000
Western subbituminous	0.8	-	8	10,000
Western lignite	0.4	-	6	8,000
Anthracite	0.8	-	6	13,500

Source: PEDCo, 1977.

TABLE G-3

DESIGN PARAMETERS FOR THE FGD SYSTEMS

Model plant parameters for current NSPS	Characteristics and assumptions				
FGD systems	Lime	Limestone	Double alkali	Sodium solution	Magnesium oxide
Absorber type	TCA[1]	TCA	Tray	Tray	TCA
Number of stages	2	2	2	2	2
Liquid to gas ratio, L/G l/m^3 (gal/1000 acf)	5.3 (40)	8.7 (65)	2.7 (20)	1.2 (9)	5.3 (40)
Gas velocity in absorber, m/sec (ft/sec)	3.0 (10)	3.0 (10)	2.4 (8)	2.4 (8)	3.0 (10)
Flue gas temperature at absorber outlet, °C (°F)	52 (125)	52 (125)	52 (125)	52 (125)	52 (125)
Degree of reheat, °C (°F)	28 (50)	28 (50)	28 (50)	28 (50)	28 (50)
Hold tank retention time, min	10	10	6	1	10
Makeup requirement, %	-	-	5	5	7
Byproduct				H_2SO_4, Na_2SO_4	H_2SO_4

[1] **Turbulent contact absorber**

TABLE G-3 (Continued)

DESIGN PARAMETERS FOR THE FGD SYSTEMS

Model plant parameters for 90 % or greater control	Characteristics and assumptions				
FGD systems	Lime	Limestone	Double alkali	Sodium solution	Magnesium oxide
Absorber type	TCA	TCA	Tray	Tray	TCA
Number of stages	3	3	3	3	3
Liquid to gas ratio, L/G l/m^3 (gal/1000 acf)	8.0 (60)	11.3 (85)	4.0 (30)	1.6 (12)	8.0 (60)
Gas velocity in absorber, m/sec (ft/sec)	3.0 (10)	3.0 (10)	2.4 (8)	2.4 (8)	3.0 (10)
Flue gas temperature at absorber outlet, °C (°F)	52 (125)	52 (125)	52 (125)	52 (125)	52 (125)
Degree of reheat, °C (°F)	28 (50)	28 (50)	28 (50)	28 (50)	28 (50)
Hold tank retention time, min	10	10	6	1	10
Makeup requirement, %	-	-	5	5	7
Byproduct				H_2SO_4, Na_2SO_4	H_2SO_4

APPENDIX H

MEASURES TO IMPROVE FLUE GAS DESULFURIZATION AVAILABILITY AND OPERATING PROBLEMS AND SOLUTIONS

Improvement Measures

Various measures have been or can be used to maintain high levels of FGD availability. These measures which are discussed below can be grouped into maintenance methods, operating techniques, and design concepts.

Maintenance Methods

The maintenance methods applied by La Cygne and Sherburne County have succcessfully maintained a high system availability. The important factors in these maintenance programs are: (1) taking one or more modules off-line each night for inspection and cleaning, (2) use of a separate maintenance crew trained to work on the FGD system, and (3) a general dedication to gaining a better understanding of the system and how to maintain it better.

Operating Techniques

There are several operating techniques that have or can be used to contribute to maintaining a high FGD system availability. Over and underspray of mist eliminators (demisters) removes deposits from the mist eliminators. Automatic pH and process control result in more stable operation and tend to prevent major failures such as massive scaling. Finally, a staff of operators and technicians to work with the FGD system on a daily basis is very important.

Design Concepts

Each of the FGD systems examined differs somewhat in design concept. Some of the concepts that have been or potentially can be successful in enhancing availability are: (1) particulate removal before the FGD system with an electrostatic precipitator (ESP), (2) dry flue gas booster fan between the ESP and scrubber rather than a wet fan after the scrubber, (3) adequate redundancy of pumps, valves, lime/limestone feed systems, packing gland water systems, etc., (4) spray tower scrubber configuration, (5) adequate instrumentation for pH, SO_2, additive use, etc. with automatic controls, (6) indirect reheat of flue gas, and (7) adequate particle dropout area to reduce solids carryover to the mist eliminators.

The areas of improvement discussed in this section represent a composite of experience at several specific FGD units. Future FGD units are expected to include many of these improvements.

Operating Problems and Solutions

There have been and still are problems associated with FGD systems; however, many of these problems have been solved and the methods of reducing the severity of the remaining items are much better understood.

To date, the problems encountered with FGD systems and the severity of these problems varied both with system type and within units of the same system. The more common problems encountered are listed below.

- Formation of scale in the absorber and associated equipment in lime and limestone systems leading to plugging and reduced capacity.

- Plugging of mist eliminators, lines, and some types of absorbers.

- Failure of ancillary equipment such as pumps, piping, pH sensing equipment, reheaters, centrifuges, fans and duct and stack linings.

- Inadequate absorbent make-up preparation.*

- Handling and disposal of sludge in nonregenerable systems.

Scaling and Plugging

In lime and limestone systems, scaling has been a particular problem and has reduced operability. Both a soft sulfite scale and a hard sulfate scale may form in the absorber, mist eliminator, and ancillary tanks, pumps, and pipes. Specific process control techniques which have produced significant improvements include:

- Use of Magnesium

Full-scale and test facilities in this country have effectively reduced saturation and scaling by addition of magnesium to the circulating slurry. The TVA Shawnee facility, the Phillips facility, and the Paddy's Run facility demonstrated that the addition of magnesium to the lime and limestone slurry eliminated scrubber scale formation. The Bruce Mansfield and Conesville stations use lime containing magnesium oxide to prevent scaling.

- Operation at subsaturation levels for calcium sulfate and sulfite

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*Discussed in PEDCO Environmental report, Nov. 1977.

By maintaining high liquid to gas (L/G) ratios, the proportion of unreacted lime or limestone remains high relative to the absorbed SO_2. There is thus less chance of creating a supersaturated solution of sulfites or sulfates. The higher L/G ratio also improves overall SO_2 collection efficiencies. The actual L/G will vary with the type of absorber, and values in excess of 10.8 l/m^3 (80 gal/acf) have been used in spray towers.

Increased reaction tank holding time will also decrease saturation by allowing further reaction between the absorbed SO_2 and the lime or limestone slurry. Slurry residence time at the Green River facility is greater than 20 minutes, and scale formation is not a major problem.

- pH Control

Work at the EPA-Shawnee test facility has shown that an important parameter in controlling scale formation is solution pH. The measurement of pH has also received considerable attention. More rugged and dependable sensors are being used; they are located in the slurry stream where they are subject to less breakage, are more accessible, and where they yield data which is more reliable and responsive for pH control.

- Co-precipitation of sulfate

Minimizing the oxygen content in the flue gas by reducing any air in-leakage, favors co-precipitation of sulfate crystal. Therefore, air exposure is reduced by covering open reaction tanks, clarifiers, etc.

Plugging caused by deposition of solids on equipment surfaces has sometimes restricted the passage of liquids or gas in FGD systems. It is usually easily removed by flushing with water or steam. Plugging in pipes can be prevented through designs which avoid low flow velocities. Careful control of raw material particle size and screening of the slurry also decrease plugging problems, especially in spray nozzles, pipes and pumps. Since this problem is caused by the deposition of solids from the recirculating slurry, reduction of the overall amount of solids will reduce the plugging. The minimum stoichiometry that will effect the required SO_2 removal efficiency should be used. This has been demonstrated at Shawnee and LaCygne.

Erosion and Corrosion

Many problems with ancillary equipment were due to corrosion and erosion. Erosion in venturi prescrubbers has resulted from high fly ash loadings. Likewise, prescrubbers remove the bulk of any chlorides and sulfur trioxide in the gas stream; both of these components are highly corrosive. Corrosion occurs more frequently in areas after the absorber is subjected to wet saturated flue gas as opposed to areas subject to alkaline slurry streams.

There are so many factors involved in FGD operation which affect corrosion rates, that generalizations regarding corrosion resistant materials are difficult. A sufficient amount of data has been accumulated, however, to provide general guidelines for the construction of critical elements in FGD systems as summarized below:

(a) Some systems are incorporating such alloys as Hastelloy C-276, Hastelloy G, Inconel 625, Incology 825, 317L stainless steel, 904L stainless steel and Jessop JS700 in wet/day high temperature, high chloride environments, such as in presaturators. The LaCygne Station has found that these materials give excellent reheat service. The Bruce Mansfield station has had good results with Hastelloy wetted parts of the fan.

(b) Synthetic and natural rubber coatings predominate in recycle tanks, pumps, and lines. These materials have been reported to give superior erosion resistance once application problems have been overcome. For instance rubber lined pumps have been used successfully at the following facilities: Green River, LaCygne, Bruce Mansfield, and Conesville.

(c) For liners in the absorbers, exhaust ducts and stacks, a number of materials such as resins, ceramics, polyesters, polyvinyls, polyurethanes, Carboline, and Gunite, have been used with varying degrees of success. Although successful applications have been reported, widespread failures of the liners have been attributed to improper application, instability of the materials at high temperatures, inconvenience of repair, and cost-related factors. These problems are especially evident on higher sulfur coals. Extensive effort is continuing by FGD suppliers to fully solve this problem.

Equipment Design

Approaches utilized to reduce problems with ancillary equipment include:

- Recirculating Pumps - Slurry recirculation pumps provide the driving force for the liquid circuit in FGD systems. In their design, special attention must be given to an accurate service description (solution pH, specific gravity, solids content, gas entrainment, flow rates, and head). A number of general trends are evident and summarized below:

(a) New systems must incorporate spare pumps. Spare capacity from 50 percent (one spare for every two operational) to 100 percent (one spare for every one operational) is useful to avoid downtime. This type of spare equipment is found at new large stations including Bruce Mansfield and Conesville.

(b) Natural and synthetic molded rubber lining should be specified for wetted parts in the pumps.

(c) Flush-water wash systems are needed to purge the pumps of solids, which tend to settle out during periods of inactivity.

- Mist Elimination - Chevron and baffle-type mist eliminators have been and are currently being used in virtually every FGD system in the United States. The popularity of these collectors is due primarily to design simplicity, high collection efficiency (for moderate to large size drops), low pressure drop, wide-open construction, and low cost. Within these two preferred types of mist eliminators, a number of specific design and construction innovations have been implemented:

(a) Chevron designs (continuous vane construction) are predominant over baffle designs (discontinuous slat construction).

(b) Fiberglass-reinforced plastic is now used at nearly all facilities.

(c) The horizontal configuration (vertical gas flow) is also used in almost all installations for cost reasons.

(d) Two-stage designs predominate over single-stage designs, because they yielded higher elimination efficiencies.

(e) Operation at high alkali utilization.

(f) Bulk entrainment separators, perforated plates, impingement plates and other precollection devices are becoming integral parts of mist elimination systems. These reduce plugging and improve separation. The Conesville facility employs this as well as LaCygne and Coal Creek.

(g) Mist eliminator wash systems that employ intermittent, high-velocity sprays predominate over continuous wash systems. These produce a hydraulic washing effect.

Application of these approaches greatly diminishes mist eliminator problems.

- Reheat - Virtually all the FGD systems coming on-line and planned for future operation incorporate some type of stack gas reheat system. These systems heat the flue gas to avoid condensation with subsequent corrosion to downstream equipment, ductwork, and stack and to suppress plume visibility as well as enhance plume rise and pollutant dispersion. To date, a number of "wet stack" FGD systems (no reheat) have been installed and have encountered corrosion problems. The trend in reheat systems is toward heating of ambient air and mixing with the flue gas and mixing of hot untreated flue gas with scrubbed gas. In-line reheat systems have been subject to corrosion and solids deposition, the latter often occurring because of inefficient upstream mist elimination. Application of heated ambient air reheat systems essentially eliminates reheater problems.

- Fans - Fans installed immediately after an FGD system (wet fans) have experienced corrosion, chloride attack, and solids deposition problems. Deposition problems have caused fan imbalance resulting in excessive bearing wear and damage to the fan. Only two systems have this trouble: Phillips and Bruce Mansfield. The problems associated with fans installed upstream of the FGD system (dry fans) include operation at higher temperatures (over 150°C) resulting in higher gas velocities and abrasion by fly ash. Dry fan problems are more easily solved, and the tendency is toward fans upstream of the FGD system. Where necessary, however, the use of various steel alloys have made wet fans a viable alternative.

APPENDIX I

EFFECT OF COAL PROPERTIES ON FGD SYSTEMS

The major coal properties affecting FGD system design and operation are heating value and sulfur, ash, moisture, and chlorine content. The effects include:

- Heating value of coal. Affects flue gas flow rate - generally higher for lower heating value coals which also contribute a greater water vapor content to the flue gas
- Moisture content. Affects the heating value and contributes directly to the moisture content and volume of the flue gas
- Sulfur content. The sulfur content together with the allowable emission standards determines the required SO_2 removal efficiency, the FGD system complexity and cost, and also affects sulfite oxidation
- Ash content. May affect FGD system chemistry and increases erosion. In some cases it may be desirable to remove fly ash upstream from the FGD system
- Chlorine content. May require high alloy metals or linings for some process equipment and could affect process chemistry or require prescrubbing.

The importance of these factors is described in this section.

Coal Heating Value and Moisture Content

Because a power plant using a low heating value coal must fire at a higher burn rate to generate the same amount of power, such coals produce a larger volume of flue gas and greater SO_2 emissions per unit of generated power. The effect on the FGD system is twofold. First, the flue gas handling equipment, including the scrubbers, must be of a larger size to accommodate the greater gas volumes. Typically, power plant flue gas volumes may range from 5,000 to more than 7,000

m^3/hr/MW (about 3,000 to 4,000 acfm/MW), depending on the coal composition, boiler heat rate, gas temperature, and power plant elevation (or gas pressure). Secondly, the increased SO_2 emissions mean that on a megawatt basis the FGD system must treat proportionally larger quantities of SO_2. On a megawatt basis, therefore, the FGD system (as well as the power plant) equipment capacity is greater and capital and operating costs are higher for coal with lower heating value - for a given coal sulfur content and SO_2 removal efficiency.

A characteristic of lower heating value coals and coals of high moisture content is a flue gas with a greater proportion of water vapor. This leads to smaller amounts of water evaporation in the scrubbers, which in turn affects the temperature to which the gas is cooled. The overall effect is that SO_2 absorption takes place at slightly elevated temperatures. This could affect absorption efficiency, depending on the chemistry of the particular process.

Sulfur Content of Coal

The sulfur content of the coal together with the allowable emission standards determines the absolute removal rate of SO_2 in pounds per hour. For a given absorption efficiency the sulfur content of the coal directly affects the design of almost every piece of equipment in the FGD system.

For example, a lime or limestone system designed for high as opposed to low sulfur coal would have:

- Scrubbers with capacity for greater SO_2 removal
- Higher L/Gs and therefore bigger pumps and piping and higher pumping energy requirements
- Bigger fans and greater energy requirements if the improved scrubber design results in higher gas pressure drop
- Larger sized alkali storage, preparation and feed equipment
- Greater lime or limestone feed rates
- Larger scrubber recirculation tanks to maintain residence time for increased L/Gs and to provide additional time for increased SO_2 absorption load
- Greater capacity slurry solids separation equipment
- Provision for disposing of the larger waste volumes
- Increased power requirements for the larger equipment loads.

With proper design, operation and maintenance the FGD systems can achieve good availability and removal efficiency for either high or low sulfur coal. However, for higher sulfur coals the lime and limestone FGD systems are more complex and have higher capital and operating costs than a low sulfur application.

Other FGD processes are similarly affected by the sulfur content of the coal. For systems using regenerable absorbents (double alkali, magnesium oxide and Wellman Lord processes), the capacity of the regeneration section is directly proportional to the sulfur content. With high sulfur coal the overall cost of these sections (capital and operating) represents a large portion of the total cost for the system. With recovery processes there is relatively little waste but a large by-product processing cost, although the greater amount of by-product produced helps to offset these costs.

The amount of sulfite oxidized to sulfate in scrubber solutions is proportional to the relative amounts of oxygen and SO_2 absorbed. It also depends on the pH and temperature of the liquid as well as the composition of particulate emissions which may contain iron or copper that act as catalysts for the oxidation reaction. In general, however, as the gas SO_2 concentration becomes smaller, the fraction of sulfite oxidation tends to increase. For this reason, when lime or limestone scrubbing systems are used for low sulfur coal or for boilers operating on high excess air they may experience high sulfite oxidation and produce waste solids that are mainly gypsum. This can be a desirable feature since gypsum solids are more easily dewatered due to faster settling rates and higher final settled densities. Conversely the lower oxidation observed with high sulfur coals can lead to solid wastes high in sulfite and difficult to dewater.

Ash Content of Coal

Most coals fired in U.S. utility boilers contain 5 to 30 percent ash. After combustion, part of the ash falls to the bottom of the furnace and the remainder is carried upward with the flue gas. The fraction of the ash that is carried overhead is a function of the boiler design and combustion parameters. With pulverized coal firing, 85 percent or more of the ash appears as fly ash; in cyclone boilers about 20 to 30 percent of the ash goes overhead.

Fly ash can be removed upstream of the FGD system by a precipitator, fabric filter, or prescrubber, or integrally within the FGD system itself. Not all FGD processes are suitable for combined removal. Even when fly ash is removed upstream, residual ash becomes entrained in the process liquor.

Fly ash is invariably abrasive; some is chemically inert, and some is highly acidic due to SO_3 adsorption. Fly ash can cause excessive erosion, scaling and plugging of equipment. It contributes to the waste volume of throwaway processes, the loss of absorbent for regenerative processes, and may contaminate the byproduct of recovery processes. Certain coals from Wyoming, Montana, and North Dakota produce alkaline fly ash with large amounts of reactive calcium, magnesium, sodium, and potassium oxides. With combined removal of alkaline fly ash and SO_2, major reduction in the alkali makeup requirement can be realized. The presence of calcium alkali in the ash can, however, aggravate wet-dry interface problems by producing hard insoluble deposits.

In general, only processes using nonregenerable absorbents (lime, limestone, soda) can be used for the combined removal of fly ash and SO_2. The fly ash is then disposed of together with the spent absorbent. Venturi scrubbers are often used for this purpose at the expense of increased pressure drop over other absorption systems. However, the fly ash contributes to solids buildup at the wet-dry interface and causes erosion of pipes, pumps, spray nozzles, and scrubber internals.

Chlorine Content of Coal

The small amounts of chlorine in coal are converted to gaseous chloride in the boiler. The chloride is absorbed from the gas by wet scrubbing processes. Its presence provides the potential for chloride stress-corrosion, requiring in some places the use of high alloy equipment wherever rubber or other protective coatings are not applicable.

In wet scrubbing processes, dissolved chloride replaces active calcium, magnesium or sodium alkalis by their chloride salts, which are inactive in the absorption process. The alkali associated with the chloride is then lost as dissolved solids in the water portion of the waste sludge. From a cost standpoint this is particularly objectionable for magnesium and sodium based processes (or magnesium enhanced lime and limestone processes), because these alkalis are relatively expensive. For such processes, prescrubbing may be used to absorb chlorides from the flue gas upstream of the FGD system. This minimizes both alkali loss and chloride stress-corrosion problems. For lime and limestone processes, an equivalent amount of calcium is used up by the chloride (the amount is small relative to that used for SO_2 absorption), but the calcium is relatively inexpensive.

APPENDIX J

FORECASTS OF FUTURE ELECTRIC UTILITY INDUSTRY STRUCTURE

This appendix describes the method utilized to forecast future electric utility industry structure under two scenarios of possible growth. Baseline forecasts are presented for moderate and high industry growth with no change in present new source performance standards (NSPS). Additional projections are provided for growth rates and for several possible revised NSPSs. The basic tool utilized to provide these forecasts is the Utility Simulation Model, a large-scale computerized model that simulates the response of the electric utility industry to specified economic conditions, energy policies and regulatory constraints. A detailed description of the model is contained in Volumes I and II of "An Integrated Technology Assessment of Electric Utility Energy Systems" by Teknekron, November 1977. Material in this appendix was extracted from "Review of New Source Standards for SO_2 Emissions from Coal-Fired Boilers," a draft prepared for the U.S. EPA by Teknekron, 1978.

Base Year Data

The results presented here were projected from a data base containing a description of every electrical generating unit (nuclear, oil and gas-fired, hydro, geothermal and combustion turbine, as well as coal-fired) operating as of 31 December 1975, plus announced plans for new units through 1985. Beyond 1985, the model creates new generating units and sites them, by county, as needed. In order to simulate the industry's response to a pollution control regulation, including a particular NSPS SO_2 emissions from coal-fired units, a minimum set of scenario parameters must be specified.

Key among these are:

- Future growth rate in peak and average power demand
- "Future mix fractions," giving the breakdowns of new generating capacity beyond 1985 by type of generation
- Kinds of coal to be burned by each coal-fired unit, including sulfur and ash content.

Other nonair-pollution related variables that must be specified include an overall inflation rate, new plant construction costs, costs of water pollution controls, assumptions about the rate of phase-out of natural gas as a utility boiler fuel, the minimum generating reserve margin to be maintained, the size and thermal efficiency of future generating units, fuel prices and price trends, and the order in which each utility system will "dispatch" the available units to meet the projected demand.

Variables which relate directly to air pollution controls include specification of the sulfur dioxide (SO_2) particulate and nitrogen oxide (NO_x) emission limits that must be met by both old and new units; the costs of the pollution-control devices used to insure compliance (flue gas desulfurization systems, electrostatic precipitators and fabric filters, modified boiler configurations for NO_x control); and constraints on siting future units due to air quality considerations.

The basic results produced by the simulation are industry composition and fuel consumption down to the county level which

TABLE J-1

KEY SCENARIO ELEMENTS HELD CONSTANT THROUGHOUT THE ANALYSIS

Air Pollution Regulations:	State Implementation Plan emission standards (as of 8/77) for SO_2 and particulates applied to all units on-line before 1977. Full compliance assumed by 12/31/79. Current (1977) NSPS for fossil-fueled units applied to all units on-line between 1977 and 1982. Values for coal are: 516 ng/J (1.2 lb/10^6 BTU) for SO_2, 43 ng/J (0.1 lb/10^6 BTU) for particulates, and 301 ng/J (0.7 lb/10^6 BTU) for NO_x. Compliance assumed at inception.
Siting Restrictions:	Coal and oil-fired units beyond those already announced are excluded from any county containing a portion of an Air Quality Control Region qualifying for Mandatory Class I or Non-Attainment status.[a]
Conversions and Rerates:	Conversions from oil and gas to coal, as per Prohibition Orders issued by the Federal Energy Administration as of June 30, 1977, are assumed effected by 1985.[b] Additional gas phase-outs based upon FEA estimates published in 1975 are also included. All gas-fired units are retired by 1996. No new oil or gas-fired generating capacity is built after 1984. Announced uprates, derates, and retirements as per FPC Order 383-4, 1 April 1977.
Water Pollution Regulations:	Full compliance with chemical and thermal emission limits promulgated for the steam electric power industry in 1974 is assumed by 1977 and 1981, respectively.
Population:	Census Bureau Series II Projections.[3]

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[a] Mandatory Class I areas are defined in accordance with the Clean Air Act Amendments of 1977: wilderness areas and memorial parks exceeding 5,000 acres, national parks exceeding 6,000 acres. Non-attainment areas are those counties with a recorded violation of any National Ambient Air Quality Standard in 1975.

[b] Oil and gas-fired units which began operation before 1977 but convert to coal in 1977 or later are assumed to be subject to the applicable SIP coal limit, not the NSPS.

consists of generating mix, fuel consumption, reserve margins and capacity factors.

Specification of Scenarios

The set of key input variables, which must be specified before a simulation can be run collectively, defines one scenario. These variables can reflect both broad national policies or region-specific assumptions such as the fraction of post-1985 baseload nuclear generating capacity in a particular state.

The quantity of data needed to fully define a scenario is too extensive to be discussed here. Table J-1 summarizes assumptions that are common to all scenarios analyzed to date (Teknekron, Inc., 1978).

The key scenario elements that vary among the scenarios are the assumed growth rate in demand for electricity and the revised NSPS being analyzed, the latter being applied only to coal-fired units of at least 25 MWe on-line in 1983 or later. Table J-2 summarizes the two sets of demand growth scenarios considered.

TABLE J-2

NATIONAL ELECTRICITY DEMAND GROWTH RATES

(Percent per year)

	1975-1985		1986-2000	
	Peak	Average	Peak	Average
Moderate growth	5.8	5.8	3.4	3.4
High growth	5.8	5.8	5.5	5.5

The alternative NSPS's that were considered involve one change in the particulate and NO_x standards, combined with three different SO_2 standards:

SO_2: Ninety percent post-combustion SO_2 removal with an upper limit ("cap") on emissions of 520 ng/J (1.2 lb/10^6 Btu)

Eighty percent post-combustion SO_2 removal with an upper limit on emissions of 520 ng/J (1.2 lb/10^6 Btu)

No fixed percentage of SO_2 removal with an upper limit on emissions of 220 ng/J (0.5 lb/10^6 Btu)

Particulates: A limit on emissions of 12.9 ng/J (0.03 lb/10^6 Btu)

NO_x: A limit on emissions of 260 ng/J (0.6 lb/10^6 Btu).

The "moderate" growth cases are meant to reflect a successful conservation effort as envisioned by the President's National Energy Plan (U.S. Congress, 1977). (Assumptions about natural gas phase-outs and oil and gas conversions to coal are also designed to reflect the goals of the National Energy Plan.)

The nomenclature used to label results from the nine different scenarios analyzed is: the letter "M" or "H" first indicates whether the "moderate" or "high" growth assumption was used. This is followed by three numbers which specify the SO_2 emission "cap" (in lb/10^6 Btu). Since the NO_x limit was set at 260 ng/J (0.6 lb/10^6 Btu) in all cases but the baseline scenarios (no NSPS revisions), its value is not indicated explicitly. The scenarios are summarized in Table J-3.

TABLE J-3

ALTERNATIVE NSPS SCENARIOS

Scenario Label	Revised NSPS in lb/10^6 BTU (% Removal)
M1.2(0)0.1 (Baseline with moderate growth)	SO_2 = 1.2 (0) NO_x = 0.7 Particulates = 0.1
H1.2(0)0.1 (Baseline with high growth)	Same as above
M1.2(90)0.1	SO_2 = 1.2 (90) NO_x = 0.6 Particulates = 0.1
H1.2(90)0.1	Same as above
M1.2(90)0.03	Same as M1.2(90)0.1 but with particulates = 0.03
H1.2(90)0.03	Same as H1.2(90)0.1 but with particulates = 0.03
M1.2(80)0.03	SO_2 = 1.2 (80) NO_x = 0.6 Particulates = 0.03
H1.2(80)0.03	Same as above
M0.5(0)0.03	SO_2 = 0.5 (0) NO_x = 0.6 Particulates = 0.03

Industry Projections

The following sections characterize the utility industry* in the base year (1975), and then project that configuration into the future. The characteristics are the capacity mix, i.e., aggregate generating capacity broken down by type of generation (coal, oil, nuclear, etc.); the distribution of generating units by regulatory category (SIP, NSPS, or revised NSPS); and the amount of capacity using FGD.

Because the Utility Simulation Model takes into account many of the complex interactions that occur among utilities' pollution control compliance strategies and their other planning and dispatching decisions, projections of characteristics like capacity mix are not made independent of the particular pollution control scenario considered. To illustrate, a decision to comply with an SO_2 emission limit through use of FGD will result in a generating capability reduction that must eventually be compensated for somewhere in the system. If that utility system's reserve margin is ample, then the lost capacity can be compensated for in the short term by running the existing units at higher levels. If the reserve is already near the safe minimum, however, the utility may be forced to plan for increased capacity additions, either by building more combustion turbines in the short term, or accelerating planned building schedules in the long term. Regardless of the particular system, more capacity will have to be added in the long run if a substantial number of units are forced to use FGD because of a new air emissions regulation. Fuel consumption also varies with emission control strategy. For example, increased use of FGD in the Midwest and East will tend to encourage the use of locally available medium and high sulfur coals at the expense of more distant supplies of low sulfur western coal. This in turn changes the average heating value of the fuel, resulting in a change in the tonnage of coal burned by the industry.* It also decreases energy consumption by rail transit systems since low sulfur coal is not transported to mideast locations.

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*The investor-owned sector and the publicly owned sector (municipal systems plus the Tennessee Valley Authority and other Federal projects) are treated together.

Capacity Mix in the Base Year

Table J-4 defines the geographical regions used in reporting capacity mix and other industry characteristics. Table J-5 shows the electrical generating capacity as of December 1975, included in the data base. Two key scenario variables involved in projecting this base-year capacity mix to any future year are the electrical demand growth rates that apply to each region and the future fractions used in adding new units once the files of announced units for a given state have been exhausted. State-level growth rates are scaled from the national average values shown in Table J-2 according to population

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*The amount of coal that must be combusted to yield 1 kWh of electrical energy is given by the unit's heat rate (a way of expressing thermal conversion efficiency) divided by the coal's heating value. It takes about 1 lb of coal to produce one 1 kWh from a modern coal-fired boiler. Variations in tonnage burned among the control scenarios considered here were found to be insignificant (less than 1 percent variation).

TABLE J-4

DEFINITION OF GEOGRAPHIC REGIONS

New England (NE)	Mid-Atlantic (MA)	S. Atlantic (SA)	E.N. Central (ENC)
CT	NY	DE	WI
RI	PA	MD/DC	MI
MA	NJ	VA	IL
NH		WV	IN
VT		NC	OH
ME		SC	
		GA	
		FA	

E.S. Central (ESC)	W.N. Central (WNC)	W.S. Central (WSC)
KY	ND	TX
TN	SD	OK
MS	NB	AR
AL	KS	LA
	IA	
	MO	
	MN	

N. Mountain (NM)	S. Mountain (SM)	Pacific (PA)
ID	NV	WA
MT	UT	OR
WY	CO	CA
	AZ	
	NM	

NOTE: The first seven and the last region are identical to Bureau of the Census regions.

TABLE J-5

UTILITY GENERATING CAPACITY AS OF DECEMBER 31, 1975[b]

(Gigawatts)

Region[a]	Nuclear	Coal	Oil	Gas	Hydro	Combustion Turbine	Other[c]	Total
NE	5.0	0.6	11.5	0.03	2.5	1.1	0.4	21.1
MA	10.5	18.5	22.3	0.04	6.7	10.4	0.2	68.6
SA	8.5	46.3	17.8	1.6	6.0	8.0	0.8	89.0
ENC	8.8	62.2	4.8	1.7	3.1	4.4	2.3	87.3
ESC	2.1	27.9	1.3	2.9	5.9	0.5	2.2	42.8
WNC	3.4	13.2	0.2	6.3	3.1	3.0	1.1	30.3
WSC	0.8	2.6	3.2	50.1	2.3	1.8	0.2	61.0
NM	0.	3.9	0.07	0.02	2.9	0.	0.1	7.0
SM	0.	13.3	1.4	2.7	3.1	1.1	0.6	22.2
PA	2.3	1.4	19.1	3.0	30.0	1.1	0.7	57.6
Nation	41.4	189.9	81.7	68.4	65.6	31.4	8.6	487.0

[a] See Table 2-1 for definitions.

[b] Average of summer and winter capabilities. The total is 96% of the name-plate capacity reported by the Edison Electric Institute.

[c] Geothermal + combined cycle + internal combustion (diesel) generators.

growth. States whose growth is projected to be higher or lower than the national level will have higher or lower demand growth rates, respectively, with the scaling being done so as to maintain the originally specified national energy demand (or average power) growth.* Average compound growth rates for the periods 1976-1985 and 1986-1995 derived by this process are given in Table J-6.

TABLE J-6

SCALED ENERGY DEMAND GROWTH RATES, BY REGION

(Average compound growth rate in percent per year)

	Moderate Growth Scenarios		High Growth Scenarios	
Region[a]	1976-1985	1986-1995	1976-1985	1986-1995
NE	5.6	3.4	5.6	5.5
MA	5.5	3.3	5.5	5.4
SA	6.2	3.7	6.2	5.9
ENC	5.6	3.3	5.6	5.4
ESC	6.0	3.4	6.0	5.5
WNC	5.2	3.0	5.2	5.1
WSC	5.6	3.3	5.6	5.4
NM	4.6	2.8	4.6	4.8
SM	6.3	3.8	6.3	5.9
PA	5.7	3.4	5.7	5.5
Nation	5.8	3.4	5.8	5.5

[a] See Table J-4.

There is no tractable decision rule for predicting the proportions of future units built beyond the base year planning horizon that will be nuclear. Therefore, future-mix fractions are specified exogenously to the model. These may be made to vary with the emission control scenario, or held constant. The fractions used in deriving the results presented may be found in "Effects of Alternative New Source Performance Standards for Coal-Fired Electric Utility Boilers on the Coal Markets and on Utility Capacity Expansion Plans" by ICF, Inc., 1978. Coal assignments and coal-unit dispatch orders, by regulatory category, were also taken from data contained in this source. The approach used was to hold constant the amount (megawattage) of nuclear capacity in 1995, i.e., independent of both the post-1985 growth rate and the control scenario. The rationale used to justify keeping the nuclear capacity the same under the moderate and high growth cases is that a variety of regulatory and other constraints are operating which would hinder the acceleration of nuclear building schedules beyond those currently envisioned by 1990, and that the amount of building assumed is already set at an optimistic level. The reason for not attempting to quantify the shift to nuclear units that might occur as a result of the imposition of more stringent emission standards on coal units beyond 1990 is related: this issue is too complex to model realistically, at least within the context of the current study, because: (1) many of the important determinants of a utility's decision whether to "go nuclear" are not quantifiable (e.g., the expected licensing period); 2) those measures that are quantifiable in principle, such as relative power generating costs, are impossible to predict accurately in the 1990 time frame due to great uncertainties in the cost data.

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*A national peak growth rate has less physical meaning, since the time of peak power demand varies widely across the country.

Projections to 2000

Capacity mixes for the two baseline scenarios (M1.2(0)0.1 and H1.2(0)0.1) and the two 90-percent control scenarios (M1.2(90)0.1 and H1.2(90)0.1) are shown in Table J-7. Note that although the total capacity in 1995 does not vary when the more stringent SO_2 controls are imposed, there is a slight increase in nuclear capacity with a corresponding decrease in coal-fired capacity. Note again that this shift is not due to conclusions about the relative economics of coal vs. nuclear generation in the future. One factor that does operate is that capacity penalties incurred when FGD systems are applied to coal-fired units, are, over the long term, partially compensated for by increased nuclear capacity. Note that the tabular values are net "capability," i.e., generating capacity after reductions due to all pollution control devices are taken into account; these may add to 10 percent of the "nameplate" capacity. The values for coal capacity under the more stringent control scenarios would increase by roughly 5 percent in 1995. Since nuclear units have only water pollution controls, the nameplate capacities of the nuclear units would increase by a smaller fraction, and would be independent of the SO_2 controls assumed.

Two other aspects of the planning algorithms used by the model to create new capacity, once the announcements data file for a given state has been exhausted bear upon the amount of nuclear capacity

TABLE J-7

PROJECTED CAPACITY MIX FOR SELECTED SCENARIOS

(Net capability, Gigawatts)

	1985				1995				Additions (1977-1995)			
	a	A	b	B	a	A	b	B	a	A	b	B
COAL	285.	283.	285.	284.	417.	403.	601.	589.	219.	204.	403.	390.
OIL & GAS	159.	159.	159.	159.	125.	125.	125.	125.	-32.3	-32.3	-32.3	-32.3
COMB CYCLE	8.00	8.00	8.00	8.00	8.00	8.00	10.6	10.7	6.80	6.80	9.40	9.50
HYDRO	86.1	86.1	86.1	86.1	87.9	86.2	90.5	86.5	20.5	18.8	23.1	19.1
TURBINE	68.8	69.0	68.9	68.8	78.1	80.0	101.	108.	36.2	38.1	59.0	66.0
GEOTHERMAL	1.70	1.70	1.70	1.70	1.90	1.90	1.90	1.90	1.60	1.60	1.60	1.60
NUCLEAR	138.	138.	137.	139.	365.	378.	379.	387.	358.	338.	339.	347.
TOTAL	747.	745.	746.	747.	1083.	1082.	1309.	1308.	610.	575.	803.	801.

Legend:

a = M1.2(0)0.1 (moderate growth baseline)
A = M1.2(90)0.1/0.03 (moderate growth, 90 percent SO_2 removal on post 1982 units, either particulate limit)

b = H1.2(0)0.1 (high growth baseline)
B = H1.2(90)0.1/0.03 (high growth, 90 percent SO_2 removal on post 1982 units, either particulate limit)

added in the 1990s.* New baseload units are added in discrete sizes, not in the exact amount of capacity needed to bring the reserve margin up to the minimum.** Secondly, the specified future fractions are used only in a probabilistic sense. For example, specifying that 70 percent of the post-1985 capacity built in a New England state will be nuclear, is interpreted by the model as a 7 out of 10 probability that a new unit will be nuclear. As a result, the exact amount of nuclear capacity installed by any year beyond 1985 cannot be "clamped" exogenously. This reflects planning uncertainties in the real world, and complicates the process of isolating the impacts of changing standards applied to fossil-fueled units. Aggregate nuclear capacity can be adjusted by trial and error. This adjustment was made for the H1.2(90)0.03 scenario, in which the initial model runs produced higher nuclear values than shown in these results.

Table J-8 shows capacity mix by geographic region for the baseline scenario with moderate growth (M1.2(0)0.1). The last column gives the capacity additions over the years 1985-1995, the period over which new builds are determined primarily by the future-mix fractions.

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*Announced units are not necessarily put into operation on the date the utility has projected: units are deferred if the specified demand growth does not justify operation until a later date. It is assumed, however, that construction schedules may not be shortened, and combustion turbines are built in the short term if more announced units are available at a later date.

**The sizes are: nuclear - 1,200 MW, coal - 600 MW, and oil - 500 MW.

TABLE J-8

PROJECTED CAPACITY MIX, BY REGION, FOR THE BASELINE SCENARIO WITH MODERATE GROWTH

(Net generating capability, Gigawatts)

New England	1976	1985	1995	1985-1995
COAL	0.58	1.34	3.97	2.63
OIL & GAS	11.9	13.2	13.1	-0.10
COMB CYCLE	0.08	0.31	0.31	0.0
HYDRO	2.53	2.53	2.53	0.0
TURBINE	1.52	2.28	2.28	0.0
GEOTHERMAL	0.0	0.0	0.0	0.0
NUCLEAR	4.14	9.87	20.0	10.13
TOTAL	20.8	29.5	42.2	12.70

Mid Atlantic	1976	1985	1995	1985-1995
COAL	20.3	24.5	38.2	13.7
OIL & GAS	24.5	25.0	24.1	-0.9
COMB CYCLE	0.13	0.13	0.13	0.0
HYDRO	6.69	8.05	8.05	0.0
TURBINE	10.6	13.1	13.1	0.0
GEOTHERMAL	0.0	0.0	0.0	0.0
NUCLEAR	7.38	21.5	51.6	30.1
TOTAL	69.6	92.3	135.2	42.9

South Atlantic	1976	1985	1995	1985-1995
COAL	41.2	53.8	80.6	26.8
OIL & GAS	22.4	24.1	23.6	-0.5
COMB CYCLE	0.0	1.40	1.40	0.0
HYDRO	5.74	9.72	9.78	0.06
TURBINE	9.10	15.1	15.5	0.4
GEOTHERMAL	0.0	0.0	0.0	0.0
NUCLEAR	9.67	27.5	72.0	44.5
TOTAL	88.1	131.6	202.9	71.3

TABLE J-8 (Continued)

PROJECTED CAPACITY MIX, BY REGION, FOR THE BASELINE SCENARIO WITH MODERATE GROWTH

(Net generating capability, Gigawatts)

East North Central	1976	1985	1995	1985-1995
COAL	69.1	89.5	104.3	14.80
OIL & GAS	7.28	8.62	8.59	-0.03
COMB CYCLE	0.0	0.0	0.0	0.0
HYDRO	3.13	3.17	3.17	0.0
TURBINE	6.80	11.7	12.0	0.30
GEOTHERMAL	0.0	0.0	0.0	0.0
NUCLEAR	8.69	28.8	79.3	50.5
TOTAL	95.0	141.8	207.4	65.6

East South Central	1976	1985	1995	1985-1995
COAL	30.5	37.0	44.6	7.60
OIL & GAS	4.32	4.63	4.33	-0.30
COMB CYCLE	0.0	0.0	0.0	0.0
HYDRO	5.98	7.53	7.53	0.0
TURBINE	2.69	3.06	3.13	0.07
GEOTHERMAL	0.0	0.0	0.0	0.0
NUCLEAR	2.30	18.0	39.0	21.0
TOTAL	45.8	70.2	98.6	28.4

West North Central	1976	1985	1995	1985-1995
COAL	18.5	31.7	42.7	11.0
OIL & GAS	4.96	2.77	2.74	-0.03
COMB CYCLE	0.0	0.09	0.09	0.0
HYDRO	3.00	4.00	4.00	0.0
TURBINE	4.81	7.88	8.50	0.62
GEOTHERMAL	0.0	0.0	0.0	0.0
NUCLEAR	4.00	6.28	14.0	7.72
TOTAL	35.3	52.7	72.0	19.3

TABLE J-8 (Concluded)

PROJECTED CAPACITY MIX, BY REGION, FOR THE BASELINE SCENARIO WITH MODERATE GROWTH

(Net generating capability, Gigawatts)

West South Central	1976	1985	1995	1985-1995
COAL	2.78	19.6	58.4	38.8
OIL & GAS	57.1	57.0	25.6	-31.4
COMB CYCLE	0.23	0.46	0.46	0.0
HYDRO	2.32	2.57	2.57	0.0
TURBINE	2.78	5.83	12.4	6.57
GEOTHERMAL	0.0	0.0	0.0	0.0
NUCLEAR	0.90	9.03	34.0	25.0
TOTAL	66.1	94.5	133.4	38.9

N. Mountain	1976	1985	1995	1985-1995
COAL	1.27	3.03	5.27	2.24
OIL & GAS	0.07	0.07	0.07	0.0
COMB CYCLE	0.0	0.0	0.0	0.0
HYDRO	3.15	3.89	3.93	0.04
TURBINE	0.08	0.60	0.61	0.01
GEOTHERMAL	0.0	0.0	0.0	0.0
NUCLEAR	0.0	0.0	0.0	0.0
TOTAL	4.57	7.59	9.88	2.29

S Mountain	1976	1985	1995	1985-1995
COAL	12.8	19.5	27.1	7.6
OIL & GAS	3.50	3.26	2.18	-1.08
COMB CYCLE	0.23	0.51	0.51	0.0
HYDRO	3.14	3.67	3.67	0.0
TURBINE	1.75	2.73	2.83	0.10
GEOTHERMAL	0.0	0.0	0.0	0.0
NUCLEAR	0.0	0.67	7.73	7.06
TOTAL	21.4	30.3	44.0	13.7

Pacific	1976	1985	1995	1985-1995
COAL	1.37	4.51	12.3	7.8
OIL & GAS	21.4	20.7	20.5	-0.2
COMB CYCLE	0.57	5.08	5.08	0.0
HYDRO	31.7	41.0	42.6	1.6
TURBINE	1.77	6.56	7.66	1.1
GEOTHERMAL	0.32	1.72	1.93	0.21
NUCLEAR	3.39	16.2	47.0	30.8
TOTAL	60.5	95.8	137.0	41.3

The age distribution of coal-fired units is particularly important in this study since the NSPS revisions are applied only to those units that come into operation in 1983 or later: Key dates are:*

Year On-Line	Applicable Category of Emission Standards
1976 or earlier	State Implementation Plan (SIP)
1977-1982	New Source Performance Standards
1983 or later	Revised New Source Performance Standards

Table J-9 gives the age breakdown by category in 5-year intervals from 1980 to 1995. In 1985, emission changes due to a NSPS revision affect only 11.5 percent of net generating capacity. With the lower growth rate, less than half of the coal-fired capacity would be subject to the revised standard by 2000, the last year of the simulation. With higher growth, the fraction in that year is 69 percent.

Table J-10 gives projections of flue gas desulfurization (scrubber) capacities for all the SO_2 control variants, assuming the revised particulate limit of 12.9 ng/J (0.03 lb/10^6 Btu). The numbers listed under "Capacity of FGD Systems" are measures of the size of the scrubbers, not of the units being scrubbed. These two capacities can differ, because the pollution control module allows for partial scrubbing of the flue gas. More specifically, full scrubbing is assumed only when the required SO_2 removal equals or exceeds 90 percent. Less than 90 percent removal is achieved by

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*The Clean Air Act stipulates that the revised new source standard will apply to those units whose construction commences after publication of the proposed revision. The definition of "commence construction" is somewhat at issue, and construction periods vary: a fixed year of implementation, 1978, is assumed.

TABLE J-9
PROJECTED COAL-FIRED CAPACITY BY REGULATORY CATEGORY

(Net generating capability, Gigawatts)

Moderate Growth Scenarios

Year	SIP Units	NSPS Units	Revised NSPS Units	Total
1980	206.8 (87.4%)	29.8 (12.6%)	0.0 (0%)	237
1985	212.5 (74.7%)	39.3 (13.8%)	32.7 (11.5%)	285
1990	212.1 (59.7%)	39.3 (11.1%)	103.9 (29.2%)	355
1995	212.1 (50.8%)	39.3 (9.4%)	166.0 (39.8%)	417
2000	212.1 (43.5%)	39.3 (8.1%)	236.4 (48.5%)	488

High Growth Scenarios

Year	Units	Units	Revised NSPS Units	Total
1980	206.9 (87.4%)	29.8 (12.6%)	0.0 (0%)	237
1985	212.6 (74.7%)	39.3 (13.8%)	32.7 (11.5%)	285
1990	212.3 (50.3%)	39.3 (9.3%)	170.8 (40.4%)	422
1995	212.3 (35.3%)	39.3 (6.5%)	349.7 (58.2%)	601
2000	212.3 (25.8%)	39.3 (4.8%)	570.1 (69.4%)	822

TABLE J-10

PROJECTED COAL CAPACITY USING FLUE GAS DESULFURIZATION

(Net capability, Gigawatts)

Scenario	Year	Unit Category	Generating Capacity	Capacity of FGD Systems[a]
M1.2(0)0.1	1985	SIP and NSPS	285	52.2
		All	285	52.5
	1990	SIP and NSPS	355	61.3
		All	355	61.3
	1995	SIP and NSPS	417	67.1
		All	417	67.1
	2000	SIP and NSPS	487	75.1
		All	487	75.1
M1.2(90)0.03[b] (M1.2(90)0.1)	1985	SIP and NSPS	252	38.7
		Revised NSPS	31.2	35.5
		All	283	74.2
	1990	SIP and NSPS	252	38.7
		Revised NSPS	94.8	106
		All	347	145
	1995	SIP and NSPS	252	38.7
		Revised NSPS	151	168
		All	403	207
	2000	SIP and NSPS	252	38.7
		Revised NSPS	212	236
		All	464	275
H1.2(0)0.1	1985	SIP and NSPS	285	45.6
		All	285	45.6
	1990	SIP and NSPS	423	59.4
		All	423	59.4
	1995	SIP and NSPS	602	76.5
		All	602	76.5
	2000	SIP and NSPS	822	99.7
		All	822	99.7

TABLE J-10 (continued). PROJECTED COAL CAPACITY USING FLUE GAS DESULFURIZATION

(Net capability, Gigawatts)

Scenario	Year	Unit Category	Generating Capacity	Capacity of FGD Systems[a]
H1.2(90)0.03[b]	1985	SIP and NSPS	243	31.0
(H1.2(90)0.1)		Revised NSPS	39.2	34.0
		All	282	65.0
	1990	SIP and NSPS	243	31.0
		Revised NSPS	167	185.0
		All	410	216.0
	1995	SIP and NSPS	243	31.0
		Revised NSPS	336	372.0
		All	579	403.0
	2000	SIP and NSPS	243	31.0
		Revised NSPS	543	602.0
		All	786	633.0
M1.2(80)0.03[b]	1985	SIP and NSPS	252	38.7
		Revised NSPS	40.3	31.6
		All	292	70.3
	1990	SIP and NSPS	252	38.7
		Revised NSPS	94.7	93.3
		All	347	132
	1995	SIP and NSPS	252	38.7
		Revised NSPS	151	149
		All	403	188
	2000	SIP and NSPS	252	38.7
		Revised NSPS	212	209
		All	464	248

TABLE J-10 (Concluded). PROJECTED COAL CAPACITY USING FLUE GAS DESULFURIZATION

(Net capability, Gigawatts)

Scenario	Year	Unit Category	Generating Capacity	Capacity of FGD Systems[a]
H1.2(80)0.03[b]	1985	SIP and NSPS	243	30.0
		Revised NSPS	40.5	30.1
		All	282	61.0
	1990	SIP and NSPS	243	30.0
		Revised NSPS	167	161.
		All	410	191
	1995	SIP and NSPS	243	30.0
		Revised NSPS	336	321
		All	579	351.
	2000	SIP and NSPS	243	30.0
		Revised NSPS	543	527.
		All	786	557.
M0.5(0)0.03	1985	SIP and NSPS	252	39.7
		Revised NSPS	40.5	31.6
		All	292	71.3
	1990	SIP and NSPS	252	38.7
		Revised NSPS	95.9	93.5
		All	348	132.
	1995	SIP and NSPS	252	38.7
		Revised NSPS	152	149.
		All	404	188.
	2000	SIP and NSPS	252	38.7
		Revised NSPS	212	208.
		All	464	247.

[a] See text.

[b] Differences in these results for the two different particulate scenarios are insignificant.

scrubbing less than 100 percent of the gas at 90 percent removal efficiency. The capacity of the FGD system for an individual boiler is, therefore, the generating unit's nameplate capacity, times the fraction of the gas scrubbed (a number between 0.3 and 1.0).* This is a measure of the design size of the scrubber module. Finally, note that the figures reported under "Generating Capacity" are the net of all pollution control related capacity penalties: this explains why the FGD capacities exceed the "Revised NSPS" net generating capacities for units subject to the 90-percent removal requirement.

The ±20-percent variations in the FGD capacity numbers for SIP and NSPS units in 1985 are due to differences among the scenarios in

TABLE J-11
REGIONAL BREAKDOWN OF INSTALLED FGD CAPACITY
IN 1995, SCENARIO H1.2(90)0.03
(Gigawatts)

Region[a]	Net Coal-Fired Capacity	FGD Capacity
NE	6.75	6.52
MA	59.2	42.5
SA	109.0	75.5
ENC	158.0	81.5
ESC	54.4	23.2
WNC	50.6	31.5
WSC	87.5	84.1
NM	13.9	13.9
SM	32.4	24.5
PA	25.2	20.1
Nation	597.0	403.0

[a] See Table J-4.

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*Coal sulfur values are adjusted downward to the compliance level whenever less than 30 percent SO_2 removal is required to comply with the applicable limit.

the sulfur levels of coal assigned to the units. The sulfur content and region of origin of coals used in all the scenarios were derived from the output of a coal supply model given in ICF, Inc. (1978c).

Table J-11 shows a regional breakdown of installed FGD capacity in 1995 under the high growth scenario with the 90-percent removal requirement (H1.2(90)0.03).

Salient features of these results are:

- Given the coal assignments used in this analysis, and the present SO_2 emission limitations, installed FGD capacity would amount to approximately 17 percent of net coal-fired generating capacity by 1985, remaining at approximately that level for the following decade.
- Under the high growth scenario, the 80-percent standard increases the installed FGD capacity from 59 GW to 191 GW by 1990, and from 77 GW to 351 GW by 1995.
- Increasing the removal requirement from 80 to 90 percent increases the installed FGD capacity by 10 to 15 percent by 1995, depending upon the post-1983 growth rate.
- The amount of FGD installed in response to a revised NSPS standard of 220 ng/J (0.5 lb/10^6 Btu) is nearly the same as that projected under the 80 percent removal scenario.
- The regions of the country with the highest installed scrubber capacities by 1995, assuming a 90-percent removal requirement, are West South Central (84 GW), East North Central (82 GW), and South Atlantic (76 GW). These three regions contain 60 percent of the total installed scrubbing capacity in that year.

As indicated in the previous tables, projections of capacity mix and scrubber usage are not sensitive to a revision of the current new source performance standard for particulates. This is because the coal assignments, capacity penalties, future-mix fractions and dispatch orders remain invariant. The costs of control do increase - but not enough to affect these key determinants of industry behavior. The small cost increase is due primarily to the assumption that units burning low sulfur western coals would use fabric filters rather than precipitators to comply with new source standards (ICF, 1978c). Given the control costs used in this study, elimination of this assumption might substantially increase the costs of meeting the revised particulate standard, with some noticeable differences in the industry projections.

Projections of utility coal consumption are shown in Figure J-1 for the high growth scenarios. (Variations in coal consumption due to the different SO_2 control assumptions are too small to be significant.) The curve starts in 1976 at 404 million metric tons (445 tons), which is very close to the actual utility "burn" in that year of 406 million metric tons (448 million tons) as reported by the Federal Power Commission (1977).* The curves illustrate rather dramatically the substantial difference a few percent change makes in the assumed demand growth rate. A 2-percent increase in the national average compound growth rate after 1985 (from 3.4 to 5.5 percent) results in almost double the coal consumed in the year 2000 from 910 metric tons to 1670 metric tons.

The simulation model accounts for differences between coal mined and coal burned due to tonnage loss in coal preparation plants. (Changes

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*The FPC reports both deliveries and consumption. These may differ in any given year due to changes in stockpile levels.

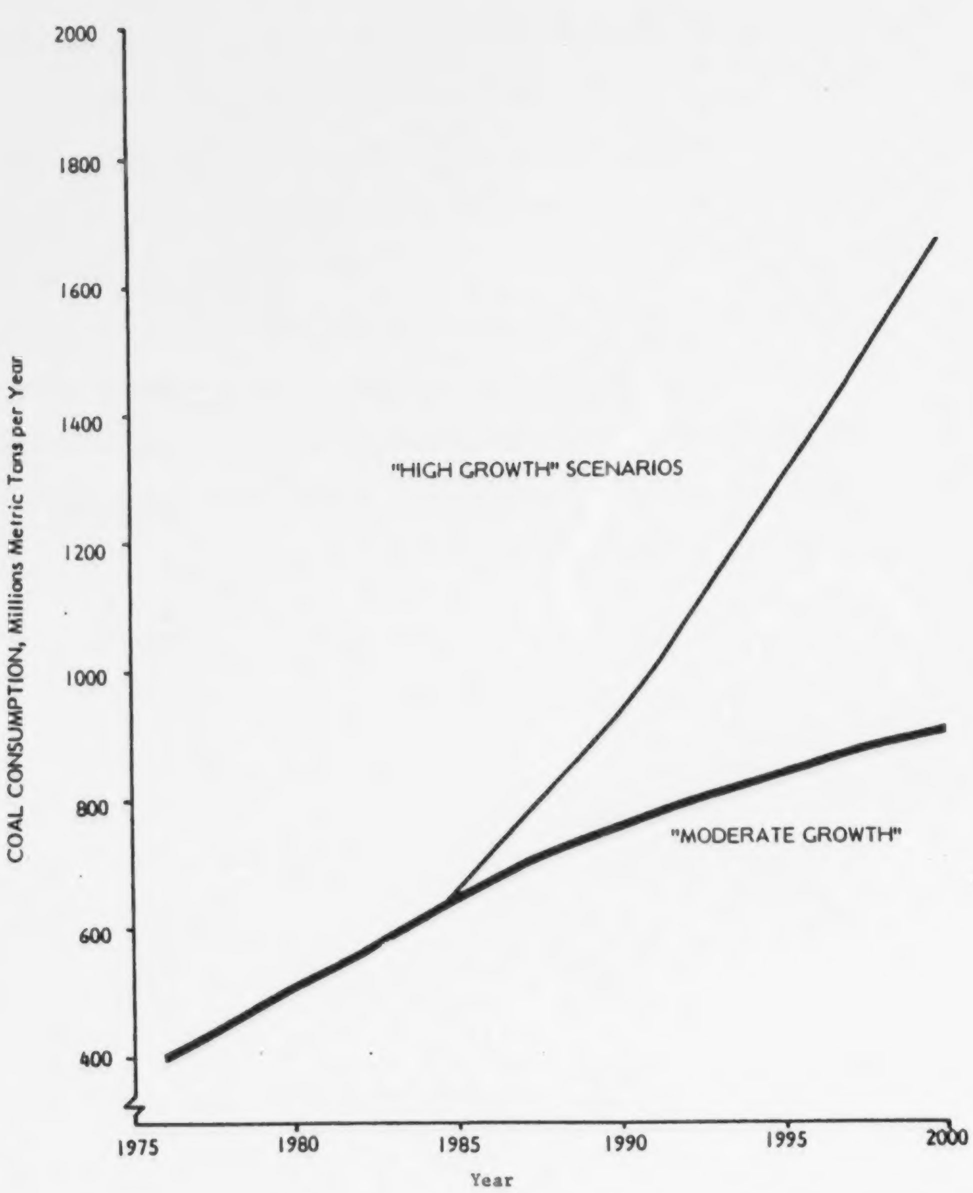

FIGURE J-1

PROJECTIONS OF ELECTRIC UTILITY COAL CONSUMPTION in utility stockpiles are not considered.) Given the sulfur levels of the coals assigned and assumptions about the minimum sulfur levels that are available in uncleaned coals, the model projects that an additional 32 million metric tons of coal would have had to be mined in 1976 to account for refuse from producing 114 million metric tons (126 million tons) of clean coal, assuming dense media separation processes with 80 percent weight recovery. This compares with the U.S. Bureau of Mines estimate of 79 million metric tons (87 million tons) of steam and metallurgical coals that were cleaned by dense media separation processes in 1975 (U.S Department of the Interior, Bureau of Mines, 1977b).

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